ERCB Energy Resources Conservation Board

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Directive 060

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Upstream Petroleum Industry Flaring, Incinerating, and Venting

The Energy Resources Conservation Board (ERCB/Board) has approved this directive for public comment on April 22, 2013.

<original signed by>

Brad McManus
Chair

Draft for Consultation

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1 Introduction

1.1 Purpose of This Directive

The Energy Resources Conservation Board (ERCB) *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* contains the requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities. *Directive 060* requirements also apply to pipeline installations that convey gas (e.g., compressor stations, line heaters, etc.) licensed by the ERCB in accordance with the *Pipeline Act*.

Most of these requirements have been developed in consultation with the Clean Air Strategic Alliance (CASA) to eliminate or reduce the potential and observed impacts of these activities and to ensure that public safety concerns and environmental impacts are addressed before beginning to flare, incinerate, or vent. *Directive 060* requirements are also aligned to ensure compliance with Alberta Environment and Sustainable Resource Development's (ESRD's) *Ambient Air Quality Objectives and Guidelines* (*AAAQO*).

Note: Appendices have been included to further the understanding of *Directive 060* requirements. See appendix 1 for a list of references and contacts, appendix 2 for definitions of terms, and appendix 3 for abbreviations.

1.2 What's New in This Edition

The key changes to this edition of *Directive 060* are summarized in *Bulletin 2013-17*. Note that the sections and appendices of this directive have been reordered as a result of these revisions.

1.3 Flaring, Incineration, and Venting Management Hierarchy and Framework

Flaring, incinerating, and venting are associated with a wide range of energy development activities and operations, including disposal of gas associated with

- oil, bitumen, and gas well drilling;
- oil, bitumen, and gas well completion or well servicing (well "cleanup");
- gas well testing to estimate reserves and determine productivity;
- routine oil or bitumen production (solution gas);
- planned nonroutine depressuring of processing equipment and gas pipelines for maintenance;
- unplanned nonroutine depressuring of process equipment and gas pipelines due to process upsets or emergency; and
- oilfield waste management facilities.

Two multistakeholder teams from CASA have made recommendations for flaring, incineration, and venting for the upstream petroleum industry, and the ERCB has based this directive on those recommendations (see appendix 4 for background on *Directive 060*).

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In particular, the ERCB has adopted CASA's objective hierarchy and its framework for managing routine solution gas flares (see figure 1) and has extended its application of the hierarchy to include flaring, incineration, and venting of gas in general.[1]

In accordance with the objective hierarchy, licensees, operators, and approval holders must evaluate the following three options:

- Can flaring, incineration, and venting be eliminated?
- Can flaring, incineration, and venting be reduced?
- Will flaring, incineration, and venting meet performance standards?

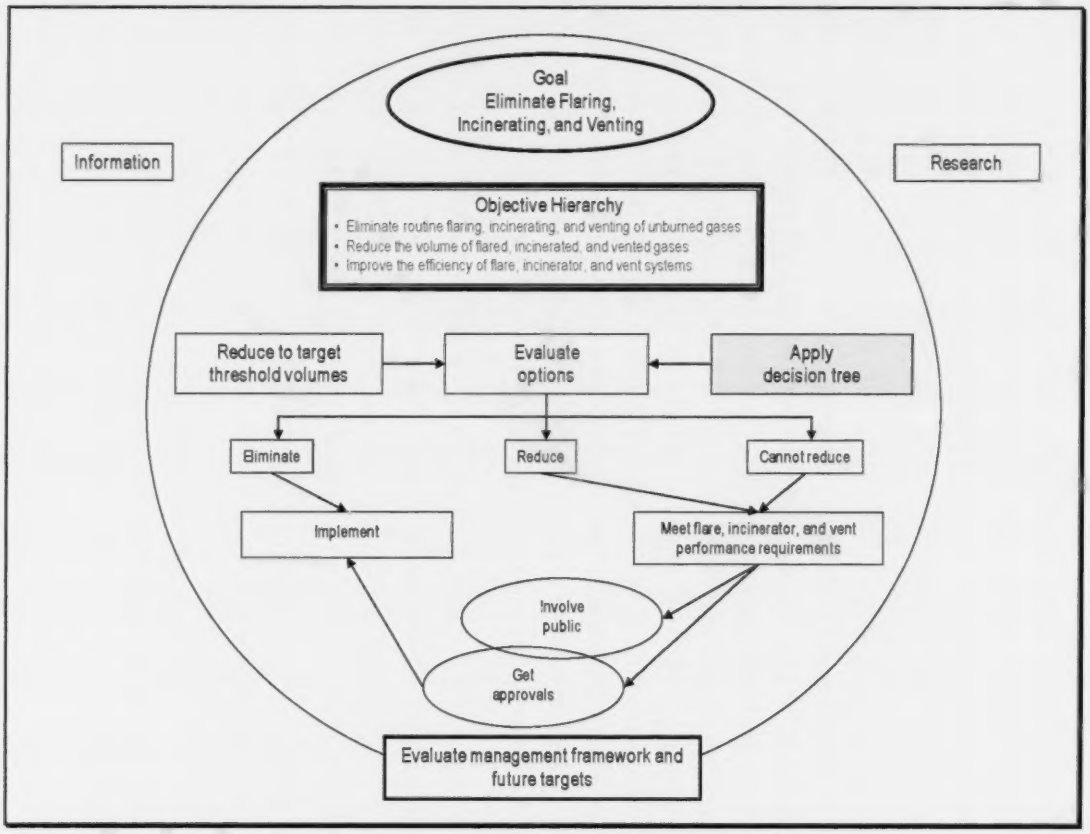

Figure 1. Solution gas flaring/venting management framework (adapted from CASA)

1.4 Access to Production Flaring, Incineration, and Venting Data

The ERCB reports flaring, incineration, and venting volumes annually in the *ST60B: Upstream Petroleum Industry* flaring report on the ERCB website www.ercb.ca under Data & Publications : Statistical Reports.

The ERCB also makes flaring, incineration, and venting information available to licensees, operators, and approval holders in order to facilitate solution gas conservation and clustering opportunities, as described in section 2.13.

[1] See CASA's 1998 *Management of Routine Solution Gas Flaring in Alberta: Report and Recommendations of the Flaring Project Team* on its website www.casahome.org.

1.5 ERCB Requirements and Compliance Assurance

ERCB requirements are those rules that a duty holder (e.g., licensee, operator, company, applicant, approval holder, or permit holder) as specified in legislation is required to follow. Terms such as "must" and "required" indicate a requirement, while terms such as "recommends" and "expects" indicate a recommended practice. In *Directive 060*, the duty holder responsible for compliance with a given ERCB requirement is as follows:

- the licensee, in the case of a licensed well, facility, or pipeline
- the operator, in the case of a facility that is exempt from a licence or approval
- the approval holder, in the case of an oilfield waste management facility

Noncompliance with any risk-assessed requirement will result in a response in accordance with the latest edition of *Directive 019: Compliance Assurance*. A list of noncompliant events is on the ERCB website www.ercb.ca under Data & Publications : Statistical Reports : ST108.

The ERCB encourages all duty holders to be proactive by monitoring their compliance with ERCB requirements. If a duty holder identifies a noncompliance, it should inform the ERCB of the noncompliance for consideration under the ERCB voluntary self-disclosure policy set out in *Directive 019*.

Further information on compliance assurance is on the ERCB website www.ercb.ca under Safety & Compliance.

1.6 Notification through the ERCB Digital Data Submission System

The licensee, operator, or approval holder must notify the appropriate ERCB field centre before planned flaring, venting, or incineration operations by completing and submitting an ERCB flaring/incineration/venting notice form within the Field Inspection System (FIS)[2] of the ERCB's Digital Data Submission (DDS) System. The ERCB strongly encourages all licensees, operators, and approval holders to follow the FIS Web User Guide when completing and submitting this form to avoid a *Directive 019* response. Any operations that may result in a public complaint must be called in to the appropriate ERCB field centre's 24-hour emergency phone number (see appendix 1).

For questions on using FIS, contact the FIS administrator by e-mail at FIS.Administrator@ercb.ca or by telephone at 403-297-4845.

[2] FIS electronically records and monitors upstream oil and gas activities and installations. The ERCB Field Surveillance and Operations Branch uses FIS to track notifications, incidents, and inspections, and to monitor compliance provincially.

2 Solution Gas Management (Crude Oil / Bitumen Battery Flaring, Incineration, and Venting)

The ERCB's goal is to have the upstream petroleum industry continue to reduce the volume of solution gas routinely flared, incinerated, and vented. The ERCB expects that the upstream petroleum industry will pursue continuous improvement in reducing solution gas flaring, incineration, and venting in Alberta, and, in consultation with stakeholders, will monitor progress to determine the need for additional requirements to facilitate increased solution gas conservation.

Combustion of solution gas in incinerators is not considered an alternative to conservation.

For solution gas management and disposition reporting, incinerated gas must be reported as flared.

Conservation is defined as the recovery of solution gas for use as fuel for production facilities, for other useful purposes (e.g., power generation), for sale, or for beneficial injection into an oil or gas pool (e.g., pressure maintenance, enhanced oil recovery). Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in section 2.9.

2.1 Solution Gas Flaring Reduction Targets

Flaring has been reduced significantly by the upstream petroleum industry. Relative to the 1996 baseline, solution gas flaring was reduced by 60 per cent by 2012. Consistent with its goal, this directive incorporates recommendations made by CASA in 2002, 2004, and 2005 to ensure that reductions in flaring continue by setting out the following limits:

1) The Alberta solution gas flaring limit is 670 million cubic metres (10^6 m^3) per year (50 per cent of the revised 1996 baseline of 1340 10^6 m^3/year) effective immediately.

2) If solution gas flaring exceeds the 670 10^6 m^3 limit in any year, the ERCB will impose reductions that will stipulate maximum solution gas flaring limits for individual operating sites based on analysis of the most current annual data so as to reduce flaring to less than 670 10^6 m^3/year. For example, solution gas flaring could be limited to a maximum of 500 thousand (10^3) m^3/year at any one site.

2.2 Solution Gas Venting Reduction

The ERCB does not consider venting an acceptable alternative to flaring. If gas volumes are sufficient to sustain stable combustion, the gas must be burned (or conserved) (see section 8.1). If venting is the only feasible alternative, the requirements in section 8 must be met.

In 2005, 59 per cent less solution gas was vented than in 2000. The CASA Flaring and Venting Project Team considered solution gas venting in the report, *Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring and Venting Project Team*, which it released in 2004.[3] The ERCB accepts these recommendations and has incorporated them into *Directive 060*.

[3] This and other reports from this team are available on CASA's web site www.casahome.org under Projects : Completed Projects : Flaring and Venting Implementation.

2.3 Solution Gas Flaring and Venting Decision Tree

The ERCB adopted the solution gas flaring/venting management framework (figure 1) and endorses the solution gas flaring and venting decision tree process (figure 2) as recommended by CASA. The licensee or operator must apply this decision tree to all flaring or venting of more than 900 m^3/day and be able to demonstrate how each element of the decision tree was considered and, where appropriate, implemented.

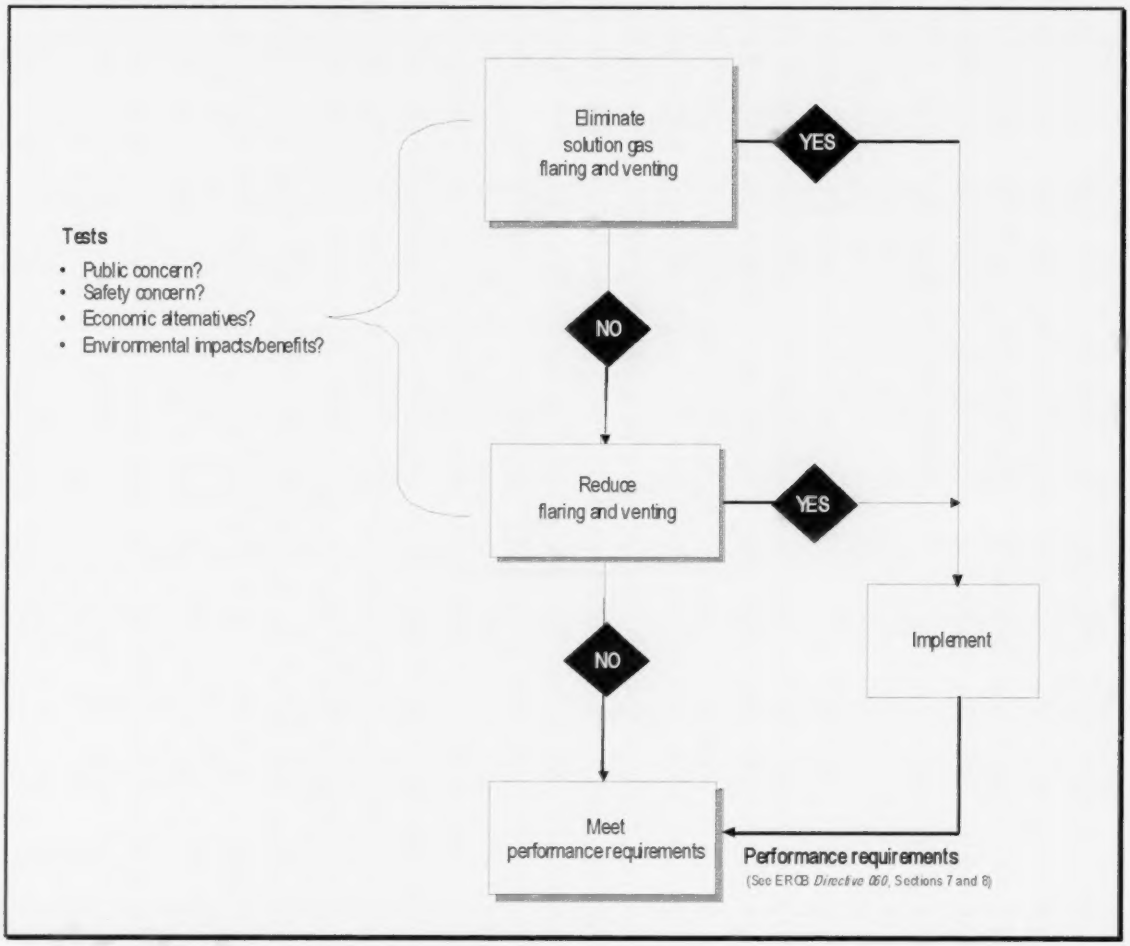

Figure 2. Solution gas flaring/venting decision tree (adapted from CASA)

2.4 Conservation at Crude Bitumen Batteries

A crude bitumen battery is an oil battery with crude bitumen production obtained from within the designated oil sands areas and that has a density of 920 kg/m^3 or greater at 15 degrees Celsius. To interpret well test duration limits, conservation timing, and conservation prebuild requirements, crude oil sites that are within the geographic area defined by the boundary of Township 45, Ranges 1 to 8, West of the 4th Meridian and Township 52, Ranges 1 to 8, West of the 4th Meridian and that are producing from the Mannville Group of formations are regulated as bitumen sites for the purpose of *Directive 060* only. See appendix 12 for the *Directive 60* area in which bitumen sites are regulated.

1) The licensee or operator of a multiwell bitumen site must build solution gas conservation lines to one common point on the lease as part of initial construction.

2) For new bitumen wells, the test period (excluding completion and cleanup operations) limit is either six months or until combined flared and vented volumes at the site exceed a rolling average of 900 m^3/day for any consecutive three-month period, whichever is less.

   a) As soon as testing shows that combined flaring and venting volumes at the site exceed 900 m^3/day, conservation must be evaluated as described in section 2.9. Volumes are calculated based on a three-month rolling average.

   b) If conservation is required, it must occur as quickly as possible and must not extend for more than six months after flow rate determination. Shorter tie-in times must be pursued wherever possible. Wells must be shut in if the required conservation is not operational within the timelines noted above.

3) If testing shows that combined flaring and venting volumes at the site do not exceed 900 m^3/day, economic evaluation of solution gas conservation is not required and the well may proceed to produce without conserving the solution gas. The ERCB, however, still recommends economic evaluation of gas conservation, even when volumes are less than 900 m^3/day.

2.5 Conservation at Conventional Crude Oil Batteries

A crude oil battery is an oil battery with crude oil production in Alberta, excluding heavy oil production that is inside the designated oil sand areas and inside the specified area producing from the Mannville Group of formations that are regulated as bitumen sites for the purpose of *Directive 060* only. See appendix 12 for the *Directive 60* area in which bitumen sites are regulated.

In general, for new oil wells the solution gas flaring during the test period must not extend beyond the time required to obtain data for the economic evaluation and for sizing conservation equipment. Any flaring for testing, cleanup, and completions must not exceed 72 hours (see section 3.2 for further details and extensions to time limits).

1) Upon completion of the testing period, if testing shows that combined flaring and venting volumes at the site will exceed 900 m^3/day, solution gas conservation must be evaluated as described in section 2.9. The wells must be shut in at the end of the test period and remain shut in pending the results of the solution gas conservation evaluation process.

   a) If the results of the solution gas conservation evaluation indicate that conservation is required, the wells must remain shut in until conservation is implemented.

   b) If the results of the solution gas conservation evaluation indicate that conservation is not required and the ERCB has not directed that conservation be implemented, the wells may proceed to produce without conserving the solution gas.

2) If testing shows that combined flaring and venting volumes at the site do not exceed 900 m^3/day and the ERCB has not directed that conservation be implemented, the wells may proceed to produce without conserving the solution gas. The ERCB, however, still recommends economic evaluation of gas conservation, even when volumes are less than 900 m^3/day.

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2.6 General Conservation Requirements at all Crude Oil and Crude Bitumen Batteries

These requirements apply to all oil and bitumen batteries unless otherwise specified.

1) The licensee or operator must conserve solution gas at all sites[4] where
   a) the combined flaring and venting volume is greater than 900 m^3/day per site[5] and the decision tree process and economic evaluation (see section 2.8) result in a net present value (NPV) greater than –Cdn$55 000;
   b) the gas:oil ratio (GOR) is greater than 3000 m^3/m^3. All wells producing with a GOR greater than 3000 m^3/m^3 at any time during the life of the well must be shut in until the gas is conserved;
   c) flared volumes are greater than 900 m^3/day per site and the flare is within 500 m of a residence, regardless of economics; or
   d) the ERCB directs the licensee, operator, or approval holder to conserve solution gas, regardless of economics.

2) For any sites flaring or venting combined volumes greater than 900 m^3 per day and not conserving, conservation economics must be completed every 12 months using the criteria in section 2.9.

3) The ERCB may still, on a case-by-case basis, require economic evaluations for sites that are flaring or venting combined volumes less than 900 m^3/day and not conserving if it is believed that conservation may be feasible.

4) Conserving facilities must be designed for 95 per cent conservation with a minimum operating level of 90 per cent.

5) The licensee or operator may apply to discontinue conservation if annual operating expenses exceed annual revenue. See section 2.6 (6).

6) The licensee or operator must get approval from the ERCB Technical Operations Group to discontinue conservation once it has been implemented at any facility, and must
   a) complete a decision tree to evaluate alternatives to discontinuing conservation,
   b) provide information on actual annual operating expenses and revenues,
   c) notify the appropriate ERCB field centre and residents within 500 m of its intention to discontinue conservation and initiate flaring or venting at a site, and
   d) if conservation facilities are not operational, comply with table 1 until such time as approval from the ERCB Technical Operations Group to discontinue conservation is granted.

2.7 Clustering

Clustering is defined as the practice of gathering the solution gas from several flares or vents at a common point for conservation. Solution gas is economic to conserve in some areas if licensees and operators coordinate their efforts in an efficient, cooperative process to take advantage of combined gas volumes and economies of scale. Furthermore, solution gas

[4] A site is defined as a single-surface lease (pads counted as one lease) where gas is flared or vented.
[5] Volumes are calculated based on a three-month rolling average.

conservation economics (see section 2.9) will be enhanced if conservation is incorporated into the initial planning of larger multiwell projects.

1) Licensees or operators of active production facilities operating within three kilometres (km) of each other or other appropriate oil and gas facilities (including pipelines) must evaluate clustering when evaluating solution gas conservation economics.

   The ERCB may suspend production in the area under consideration until the economic assessment is complete.

   The ERCB recommends that

   a) all licensees and operators exchange production data and jointly consider clustering of solution gas production or regional gas conservation systems, and

   b) the licensee or operator with the largest flare and vent volumes take the lead in coordinating the evaluation of conservation economics for the area.

2) The licensee or operator of a multiwell oil or bitumen development must assess conservation on a project or development area basis regardless of distance. Evaluations must address all potential gas vent and flare sources associated with the multiwell development.

   a) The licensee or operator must incorporate provision for conservation at all stages of project development to optimize the opportunity for economic conservation of solution gas.

   b) Applications under *Directive 056: Energy Development Applications and Schedules* for multiwell oil or bitumen developments must include a summary of the gas conservation evaluation and a description of the licensee or operator's related project plans.

The ERCB may suspend production at any facility until the economic assessment is complete.

2.8 Power Generation Using Otherwise-Flared/Vented Gas

Power generation is an alternative for conserving solution gas.

1) Approval of electrical power plants by the Alberta Utilities Commission is required under the *Hydro and Electric Energy Act*.

   Alberta Utilities Commission Rule 007: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations provides application requirements for power plant applications and includes a simplified application form for electric power generating projects of 1.0 megawatt (MW) or smaller.

2) Power plants with a generation capacity greater than 1.0 MW at peak load require approval issued by ESRD under the *Environmental Protection and Enhancement Act* (*EPEA*).

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2.9 Economic Evaluation of Gas Conservation

If conservation is determined to be economic by any method using the economic decision tree process, the gas must be conserved.

1) Methods of conservation must include pipeline to sales, fuel, power generation, pressure maintenance, or any other method that may become available.

2) Licensees or operators must update the conservation economics for any sites that are flaring or venting combined volumes of more than 900 m^3/day and that are not conserving every 12 months. This information, with the responsible individual named and the document dated, is to be kept on file by the licensee or operator and must be provided to the ERCB upon request. Evaluation information may be stored at a central location rather than on site.

3) A licensee or operator must provide the evaluation to the ERCB within five working days of receipt of a request.

4) If the ERCB Technical Operations Group determines that the economic evaluation process has not been completed in accordance with *Directive 060* requirements, the licensee or operator will be subject to a response in accordance with *Directive 019*, which may include suspension of facility operations.

2.9.1 Economic Evaluation Criteria

Economic evaluations of gas conservation must use the criteria listed below. The licensee or operator must consider the most economically feasible option in providing detailed economics. Specific ERCB economic evaluation submission requirements are listed in section 2.9.2.

1) Evaluations must be completed on a before-tax basis, and must exclude contingency and overhead costs.

2) Conservation economics must be evaluated on a royalties-in basis (paying royalties) for incremental gas and gas by-products that would otherwise be flared or vented. If the economic evaluation results in an NPV less than – Cdn$55 000, the licensee or operator must re-evaluate the gas conservation project on a royalties-out basis (not paying royalties). If the evaluation results in an NPV – Cdn$55 000 or more, the licensee or operator must proceed with the conservation project and may then apply to Alberta Energy for an "otherwise flared solution gas" royalty waiver.

3) Price forecasts used in the evaluation of solution gas conservation projects (gas gathered, processed, and sold to market) must use the most recent version of commodity price forecast from GLJ Petroleum Consultants Limited. Gas prices must be obtained from the "Natural Gas and Sulphur Price Forecast Table" in the "ARP" column ($Cdn/MMBtu). Condensate prices must be obtained from the "Crude Oil and Natural Gas Liquids Table" in the "Alberta Natural Gas Liquids Section – Edmonton Pentanes Plus" column ($Cdn/bbl).

4) Price forecasts for power generation projects must reflect the most recent 12-month rolling average of the pool monthly summary price as published by the Alberta Electric

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System Operator (AESO).[6] The power price must be escalated at the long-term inflation rate (see item 9). Alternatively, the cost of the power displaced at the site may be used.

5) The licensee or operator must have information to support the remaining reserves calculation and the production forecast (including planned drilling programs and pressure maintenance schemes). The production forecast must be calculated by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.[7]

6) The licensee or operator must have a detailed breakdown of capital costs showing equipment, material, installation, and engineering costs. Capital costs must be approved-for-expenditure quality numbers based on selection of appropriate technology. Any capital costs incurred before the initiation of the solution gas project (i.e., sunk costs) must not be included in the analysis; only future capital costs related to solution gas conservation may be included.

   b) For new flares, if capital cost savings result from implementing gas conservation, such as any equipment that would otherwise be required, the flares must be considered in the conservation economic evaluation and subtracted from the overall cost of the conservation infrastructure in evaluating the economics of solution gas tie-in.

   c) Salvage value of gas conservation infrastructure must be included as project revenue in the year the value would be realized (e.g., transfer of a gas compressor from one conservation project at the end of that project's life to another conservation project). The salvage value must be a reasonable market value estimate of the equipment and not a depreciated value from a taxation perspective.

7) The incremental annual operating costs for the gas conservation project, including gas gathering and processing fees, are to be assumed as up to 10 per cent of the initial capital cost of installing the conservation facilities. If the gas contains 10 moles per kilomole (mol/kmol) hydrogen sulphide (H_2S) or more, the incremental annual operating costs for the solution gas project may be assumed to be up to 20 per cent of the capital cost to initially install the conservation facilities.

   a) The economic evaluation must account for any cost savings, such as reduced trucking, equipment rental, and the licensee's or operator's costs that may result from the conservation project.

8) The incremental annual operating costs for power generation projects are to be assumed as up to 10 per cent of the initial capital cost of installing the generation facilities. Standby fees may be calculated in addition to this 10 per cent allowance.

9) The most recent long-term inflation rate must be based on the consumer price index forecast for Alberta, as published on the Government of Alberta, Treasury Board and Finance, Finance and Statistics website.

10) The discount rate must be equal to the prime lending rate of ATB Financial on loans payable in Canadian dollars plus 3 per cent, based on the month preceding the month the evaluation was conducted in. This rate is reviewed periodically by the ERCB and will be revised if the cost of capital for the oil and gas industry changes significantly.

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[6] The most recent 12-month rolling average of the pool monthly summary price can be found on the AESO website at http://cts.aeso.ca.

[7] *Engineering and Geoscience Professsions Act*, RSA 2000 c. E-11, as amended.

11) A solution gas conservation project is considered economic, and the gas must be conserved, if the economics of gas conservation generates an NPV before-tax of more than –Cdn$55 000.

   a) The NPV is defined as the sum of discounted, annual, before-tax cash flows for the economic life of the solution gas conservation project, where each annual before-tax cash flow is net of that year's conserving project capital investment, if any.

   b) The economic life of a conservation project is defined as the period from the start of the project to the time when annual expenses exceed annual revenue. Note that section 2.6(6) provides a process whereby the licensee or operator may apply to discontinue conservation if annual expenses exceed annual revenue.

12) If a solution gas conservation project has an NPV less than –Cdn$55 000 and is therefore considered uneconomic on its initial evaluation, the project economics must be re-evaluated annually (within 12 months of the latest evaluation) using updated prices, costs, and forecasts.

2.9.2 ERCB Economic Evaluation Audit Requirements

1) Economic evaluation audit packages submitted to the ERCB Technical Operations Group upon request must contain the following information in SI (international system of units) units:

   a) detailed capital and operating cost schedules as set out in sections 2.9.1(6) and 2.9.1(7)

   b) oil and gas reserves calculations and supporting information (including a discussion of planned drilling programs and pressure maintenance schemes)

   c) a production forecast for both the oil and gas streams and the economic limit (date and production rates) of the project based on the oil production rate (including planned drilling programs and pressure maintenance schemes)

   d) a copy of the gas analysis from the project or a representative analog complete with gas heating value and gas liquid yields

   e) documentation of alternatives that were considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation

   f) documentation of compliance with the requirements listed in sections 7 and 8

2.10 Public Involvement

Licensees or operators with continuous solution gas flares, incinerators, or vents are expected to respond to questions or concerns raised by the public in relation to activities related to the flaring, incineration, and venting of solution gas at upstream petroleum industry facilities. To help respond to the public, public information packages should be prepared and provided.

1) The licensee or operator must notify residents, the appropriate ERCB field centre, and ESRD of nonroutine flaring, incineration, and venting at production and processing facilities, as described in section 2.11, table 1.

2) The licensee or operator must not exceed minimum spacing requirements (see section 7.8).

2.10.1 Public Information Package

As a minimum, public information packages must include the following:

1) the definition of solution gas, and information on its conservation and use
2) an explanation of solution gas flaring, incineration, and venting management options and the decision tree process
3) a summary of analysis completed to determine that flaring, incineration, or venting is needed
4) information on general flare/vent performance requirements and reduction targets
5) descriptions of specific actions the licensee or operator will take to eliminate or reduce flaring, incineration, or venting or improve the efficiency of the flare, incinerator, or vent source based on the evaluation
6) a list of industry, ERCB, and government contacts that are related to public consultation and relevant to the project

2.11 Nonroutine Flaring, Incineration, and Venting at Solution Gas Conserving Facilities

The licensee or operator must minimize nonroutine flaring, incineration, and venting during upsets and outages of solution gas conserving facilities.

The ERCB also recommends that the licensee or operator contact the appropriate ERCB field centre for recommendations for minimizing solution gas flaring during outages at conserving facilities.

2.11.1 Limitations on Nonroutine Flaring, Incineration, and Venting During Outages at Solution Gas Conserving Facilities

1) Production operations must be managed to control nonroutine flaring, incineration, and venting of normally conserved solution gas in accordance with table 1 below.
2) Table 1 does not apply to nonassociated gas (the percentage cutbacks listed in table 1 apply to solution gas only). All nonassociated gas must be shut in during facility outages.
3) Table 1 does not apply to thermal in-situ production.
4) The licensee or operator must provide notification as required in table 1.
5) If there is a restriction to the plant inlet, the ERCB recommends that solution gas processing have priority over the processing of nonassociated gas in order to limit the unnecessary flaring of solution gas.
6) The ERCB recommends that wells with the highest GOR be the first to be shut in during facility outages and cutbacks.
7) Provided the overall required percentage reduction in solution gas production is achieved, it is not necessary to implement equal reductions at all locations upstream of the conserving facility outage.
    a) When multiple licensees or operators are involved, they may determine how to best implement the overall required production reductions. If an agreement cannot be reached, each licensee and/or operator must reduce production as specified in table 1.

Table 1. Limitations and notification requirements for nonroutine flaring, incinerating, and venting during solution gas conserving facility[1] outage

Shutdown category	Duration	Operational requirements
Partial equipment outages	< 5 days	Shut-in of production is not required for equipment outages last less than 5 days that involve small volumes of gas (e.g., storage tank vapour recovery unit repair). This allowance is limited to a maximum of 2 10^3 m^3 per day subject to limitation on venting as defined in section 8. If the event is ≥ 5 days, the operator must meet requirements stated below (planned shutdown category, > 4 hours duration)
Planned	< 4 hours	The licensee or operator must make all reasonable efforts[2] to reduce battery or solution gas plant inlet gas volumes by 50 per cent of average daily solution gas production over the preceding 30-day period.
	> 4 hours	The licensee or operator must reduce battery or solution gas plant inlet gas volumes by 75 per cent of average daily solution gas production over the preceding 30-day period and meet the following requirements: • Solution gas must not be flared from wells that have an H_2S content greater than 10 per cent. • Production may be sustained at rates that will provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25 per cent of the average daily solution gas production, a variance must be obtained from the appropriate ERCB field centre (see section 2.11.3). • Residents within 500 m must be notified at least 24 hours before the planned flaring event. • The ERCB also recommends that the licensee or operator notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility. • The appropriate ERCB field centre must be notified[3] if the event meets reporting requirements identified in *IL 98-01*,[4] section 4.4.
Emergency[5] or plant upset	< 4 hours	No reduction in the plant inlet is required.
	> 4 hours	The licensee or operator must reduce battery or solution gas plant inlet gas volumes by 75 per cent of average daily solution gas production over the preceding 30-day period and must meet the following requirements: • Solution gas must not be flared from wells that have an H_2S content greater than 10 per cent. • Production may be sustained at rates that will provide sufficient throughput to keep equipment operating safely and within minimum design turndown range. If this volume is greater than 25 per cent of the average daily production, a variance must be obtained from the appropriate ERCB field centre (see section 2.11.3). • Residents within 500 m must be notified without delay about the flaring event. • The ERCB also recommends that the licensee or operator notify individuals who have identified themselves to the licensee or operator as being sensitive to or interested in emissions from the facility. • The appropriate ERCB field centre[3] must be notified if the event meets reporting requirements identified in *IL 98-01*,[4] section 4.4.
Repeat nonroutine flaring[6]		The licensee or operator must investigate causes of repeat nonroutine flaring or venting and take steps to eliminate or reduce the frequency of such incidents.

[1] For the definition of conserving facility, see appendix 2.

[2] Notwithstanding solution gas reduction requirements listed in table 1, if a sour or acid gas flare or incinerator stack is not designed to meet the one-hour *AAAQO* for sulphur dioxide (SO_2) under high flow-rate conditions, action must be taken immediately to reduce gas to a rate compliant with *AAAQO* (see section 7.12.5).

[3] The appropriate ERCB field centre must be notified through the ERCB field inspection system in the DDS System. In situations where limits have been exceeded, the appropriate ERCB field centre must be contacted by telephone before DDS is notified.

[4] *IL 98-01: A Memorandum of Understanding Between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response*.

[5] Emergency shutdowns or plant upsets are unplanned events at the battery site or at facilities downstream of the battery that causes the nonroutine flaring at the battery.

[6] Repeat nonroutine flares are defined as recurring events of similar cause at a conserving facility during a 30-day period.

2.11.2 Planned Shutdown (Turnaround) Considerations

1) A licensee or operator must evaluate and implement appropriate measures to reduce solution gas flaring, incineration, and venting during a gas plant turnaround or planned shutdown. Alternatives that minimize impacts of planned shutdowns include

   a) delivering solution gas to a nearby gas plant that is not on turnaround;

   b) scheduling maintenance at related oil facilities to coincide with the gas plant turnaround;

   c) injecting solution gas into the gas cap of an oil pool or into a gas reservoir and producing it back when the gas plant is back on stream (see *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs*); and

   d) communicating with well, battery, and gas plant licensees or operators to ensure that nonroutine solution gas flaring, incineration, and venting are minimized.

2.11.3 Alternatives to Solution Gas Shut-in Requirements

The appropriate ERCB field centre will consider alternatives to the shut-in requirements listed in this directive for solution gas. This will be done only if the licensee or operator can demonstrate that shutting in a well or a group of wells may cause damage to well equipment or permanent reduction in productivity or if shutting in is impractical due to the remoteness of facilities. In these special cases, the licensee or operator must consult with the ERCB field centre about alternatives to shut-in for a particular gas plant or battery.

1) A licensee or operator must plan for outages. If an alternative to table 1 is justified, the ERCB recommends that the licensee or operator submit a written request to the ERCB field centre at least 30 days before a planned shutdown explaining the alternative requested and giving supporting reasons for the request. The ERCB recommends that wherever possible, contact with the ERCB field centre not be deferred until an actual outage occurs.

2.12 Royalty Treatment of Flared and Vented Gas

In December 1998, the Government of Alberta created the Otherwise Flared Solution Gas Royalty Waiver Program to encourage the productive use of solution gas currently being flared. For more information, see Alberta Energy *Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program*.[8]

The program is summarized as follows:

- The Alberta Department of Energy has developed criteria for ensuring that when gas can be economically conserved, it does not receive a royalty waiver.
- The program covers all methods of conserving solution gas.

2.13 Solution Gas Reporting Requirements and Data Access

2.13.1 Solution Gas Reporting Requirements

1) Flared, incinerated, and vented solution gas must be reported monthly through PETRINEX (Canada's Petroluem Information Network) as described in section 10.

a) A licensee or operator must report all new oil well production, including the test period, and obtain a battery code for any new oil wells before production, including flaring, can be reported (see *Directive 017: Measurement Requirements for Oil and Gas Operations*).

2.13.2 Cooperating with Third Parties

The ERCB recommends that the licensee or operator cooperate with qualified third parties attempting to conserve solution gas through open market or clustering efforts by providing nonconfidential information, such as gas analyses, flared and vented volumes, pressures, and other relevant data, on a timely basis (also see section 2.7).

In cases where conservation is determined by the licensee or operator to be uneconomic (as per section 2.8) but where a third party is able to conserve the gas, the ERCB recommends that the licensee or operator either conserve the gas or make the gas available at the lease boundary at no charge within three months of a request for the gas. It would be understood that this gas may be provided without processing or compression, and the third-party organization must not affect the upstream operations.

Any third party requesting data from a licensee or operator must be technically qualified and have a reasonable expectation of proceeding with the gas conservation project. Third parties must also comply with all relevant ERCB requirements.

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3 Temporary and Well Test Flaring and Incinerating

This section applies to temporary flaring and incineration activities. These activities include well testing, well cleanup, well servicing, sour gas pipeline (as defined in *Directive 056*) blowdown, coalbed methane well testing, underbalanced drilling, maintenance blowdowns, and emergency blowdowns through temporary or permanent flare or incinerator equipment.

Unplanned nonroutine flaring and incinerating (e.g., process upsets, emergencies) do not require a temporary permit. Planned nonroutine flaring and incineration events (e.g., maintenance blowdowns, pipeline depressuring, turnarounds) do require a temporary flaring or incineration permit, as stated in section 3.3.

The ERCB does not consider venting an acceptable alternative to flaring or incineration. If gas volumes are sufficient to sustain stable combustion, the gas must be burned or conserved (see section 8.1(5) for specifics on well test venting). If venting is the only feasible alternative, it must meet the requirements in section 8.

3.1 Temporary Flaring and Incinerating Decision Tree

1) Licensees must use the temporary flaring and incinerating decision tree process (figure 3) to evaluate all opportunities to eliminate or reduce flaring and incineration, regardless of volume.

2) Licensees must evaluate opportunities to use existing gas gathering systems before beginning temporary maintenance, well cleanup, or testing operations (i.e., "in-line testing"). In-line testing must be done when economic and feasible to do so. Information on the evaluation of the most feasible option (e.g., closest potential tie-in location) must be provided with permit requests (section 3.5.1). The ERCB recommends that in-line testing be used in situations where

   a) suitable infrastructure exists in proximity to the well and can be connected at moderate cost and where use of the infrastructure does not compromise integrity, or

   b) sufficient productivity information is known about a development well so that connecting pipelines can be built with minimal financial risk before testing.

3) If in-line testing is not possible, licensees must design completions and well testing programs to minimize emissions while ensuring technically sound well completion and acquisition of sufficient reservoir and productivity information for future development decisions. *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells* must be consulted on the minimum pressure and deliverability requirements for well testing and on the recommended practices in order to ensure that the appropriate information is obtained for conservation and pool management purposes in addition to the requirements of this directive.

   a) Licensees must use appropriate equipment and design temporary (maintenance, well completion, or test) programs to comply with performance requirements in section 7 and the *AAAQO*.

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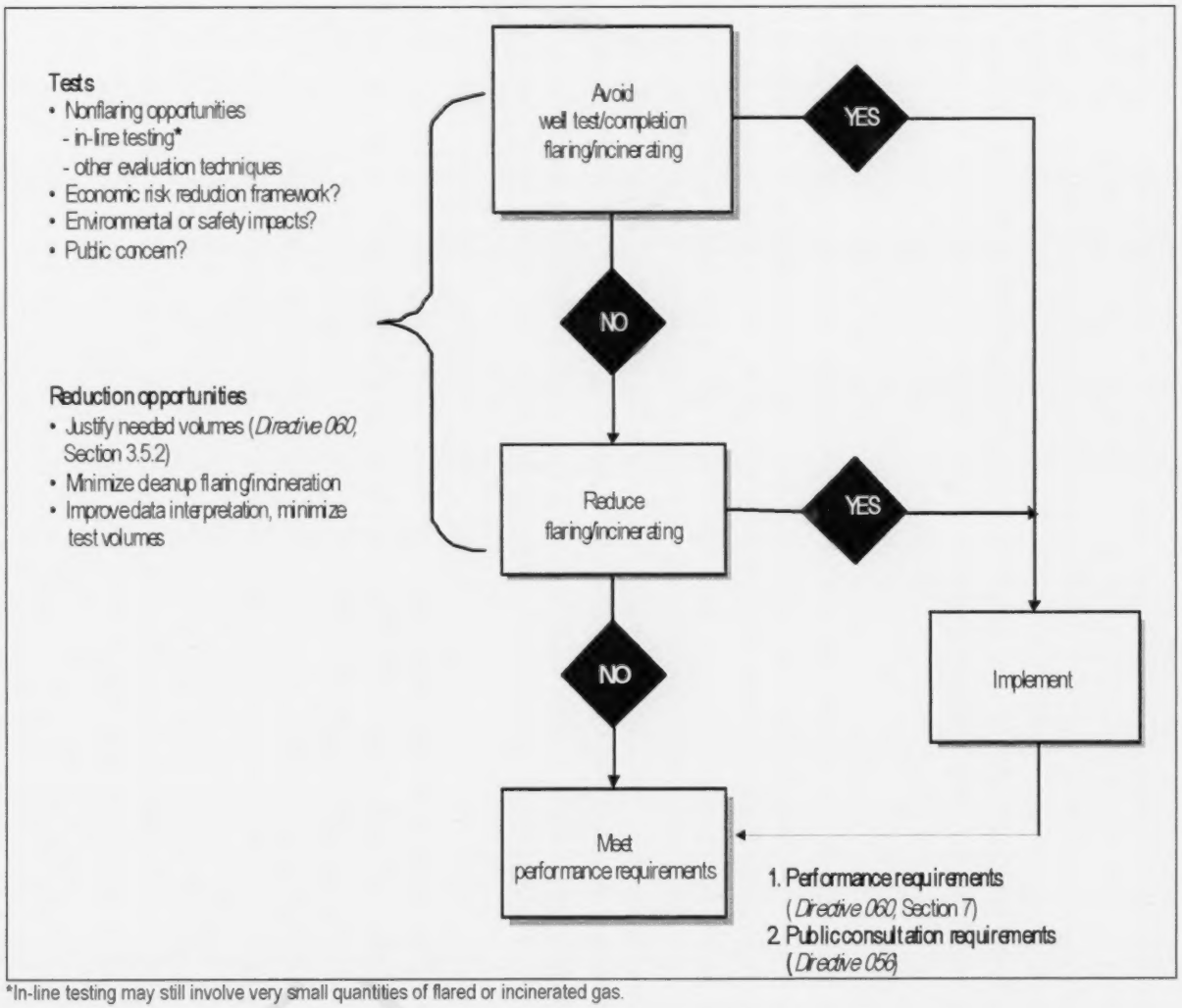

*In-line testing may still involve very small quantities of flared or incinerated gas.

Figure 3. Temporary flaring and incineration decision tree (adapted from CASA)

3.2 Oil and Gas Well Test Flaring, Incinerating, and Venting Duration Limits

To interpret well test duration limits, conservation timing, and conservation prebuild requirements, crude oil sites within the geographic area defined by the boundary Township 45, Ranges 1 to 8, West of the 4th Meridian, and Township 52, Ranges 1 to 8, West of the 4th Meridian, and producing from the Mannville Group of formations will be regulated as bitumen sites. See appendix 12 for the *Directive 60* area in which bitumen sites are regulated.

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1) These time limits are per zone, are nonconsecutive, and do not include shut-in time. These periods include flaring, incinerating, and venting during cleanup, completion, workover, and testing. Licensees and operators must not exceed the following flaring, incinerating, and venting time limits:

   a) crude oil wells/sites:[9] 72 hours

   b) bitumen wells/sites: until flow rates exceed an average of 900 m^3/day for any consecutive three-month period, not to exceed six months. See section 2.4.

   c) gas (nonassociated, noncoalbed methane) wells: 72 hours

   d) dry coalbed methane development wells (producing less than 1 m^3 of water per operating day): 120 hours

   e) dry coalbed methane nondevelopment wells (producing less than 1 m^3 of water per operating day): 336 hours

   f) wet coalbed methane wells (producing more than 1 m^3 of water per operating day): see Section 3.2(7) below

2) Extensions to the time limits listed in (1)(a), (c), (d), and (e) above are allowed only if

   a) cleanup of the wellbore is not complete. Cleanup is considered complete when the gas composition meets the minimum pipeline specifications for the nearest pipeline that could accept the gas;

   b) stabilized flow has not been reached. Refer to *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*, section 4.3, and *Directive 034: Gas Well Testing, Theory and Practice*, section 7.1; or

   c) there have been mechanical problems with the well.

3) For extensions to the time limits stated in (1)(b) and (f), licensees must request approval from the ERCB as described in (5) below.

4) The licensee must document these reasons for extension and keep the information on file for review and/or audit by the ERCB field centre when requested. The licensee is not required to ask permission to extend the flaring/incineration beyond the specified time limit listed in (1)(a), (c), (d), or (e) if the reason matches those listed in (2)(a), (b), or (c), but must notify the appropriate ERCB field centre in advance through the DDS system as soon as the licensee recognizes that the time limit will be exceeded.

   a) If an audited licensee fails to justify the need to exceed the time limitation to the ERCB field centre's satisfaction, enforcement action will apply.

5) If more time for well test flaring, incineration, or venting is needed for reasons other than those listed above, the ERCB must be contacted for approval to continue as soon as possible, and no later than the end of the specified period.

6) If a temporary flaring/incineration permit has been issued, the volume allowed in the permit will take precedence over the time limit described in (1) above.

7) When well test information indicates that cleanup is complete and the well flow is stabilized and all other ERCB requirements (e.g., ERCB *Directive 040*) are met, flaring/incineration/venting must be discontinued, even if the time limit or the flaring/incineration permit volume has not been reached. This requirement does not

[9] A site is defined as a single-surface lease (pads counted as one lease) where gas is flared or vented.

apply to bitumen or wet coalbed methane wells. Timing requirements for bitumen are in section 2.4(2). Timing requirements for wet coalbed methane wells are in (8) below.

8) For wet coalbed methane wells producing more than 1 m^3 of water per operating day, flaring/incinerating or venting must cease (gas must be conserved) within six months of gas production for an individual well exceeding a cumulative total of 100 10^3 m^3 for any consecutive three-month period (about 1100 m^3/day). Shorter tie-in periods must be pursued wherever possible.

   a) Licensees must notify the ERCB Technical Operations Group as soon as the cumulative total gas production exceeds 100 10^3 m^3 for any consecutive three-month period at a wet coalbed methane well that is flaring, incinerating, or venting.

   b) For wet coalbed methane wells that do not trigger the requirement above (i.e., 100 10^3 m^3 in three months), flaring, incineration, and venting are limited to the lesser of

      c) a total period of 18 months, including the time to tie in the well, or

      d) a total cumulative volume of 400 10^3 m^3 for tier 2 (development) wells or 600 10^3 m^3 for tier 1 (other) wells per zone tested (see section 3.3.1[2]). Wells already tied in are treated as tier 3 and allowed a maximum cumulative flare, incineration, and vent volume of 200 10^3 m^3.

   c) If additional flaring/incineration or venting durations or volumes are needed to test a coalbed methane well producing more than 1 m^3 of water per operating day, the licensee must make a written request to the ERCB Technical Operations Group as early as possible and in no case later than the end of the 18-month or volume allowance flare/incineration or vent period. Any request must include the reasons for the extension. Extensions may be granted to allow for additional flaring/incineration/vent duration or volume for reservoir evaluations or if other special circumstances warrant.

3.3 Temporary Flaring/Incineration Permits

Figure 4 depicts the temporary flaring/incineration permit process.

The ERCB may suspend well flaring or incineration for noncompliance with conditions of the permit. The licensee must comply with the conditions of the temporary flaring permit.

3.3.1 Conditions That Require a Temporary Flaring/Incineration Permit

Note that an exemption for flaring small volumes of sour gas is found in section 3.3.2(2).

1) Licensees must obtain a permit to flare or incinerate sour gas containing more than 50 mol/kmol H_2S (5 per cent) or sour gas from any well classified as a critical sour well.

   a) If operations result in H_2S concentrations that are higher than concentrations at the well (e.g., flaring gas from tanks), the composition of the gas to be burned must be determined in order to establish whether a permit is required. This composition must also be used in any required dispersion modelling.

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b) If supplemental fuel gas is used, the resulting composition must be used for dispersion modelling. However, the gas composition from the source is still used as the basis for determining whether a permit is required.

2) Licensees must obtain a permit for temporary flaring or incineration of natural gas if gas well test volumes exceed the volume allowance threshold. This is based on the volume of gas flowed back from the well (and does not include fuel gas added), regardless of composition.

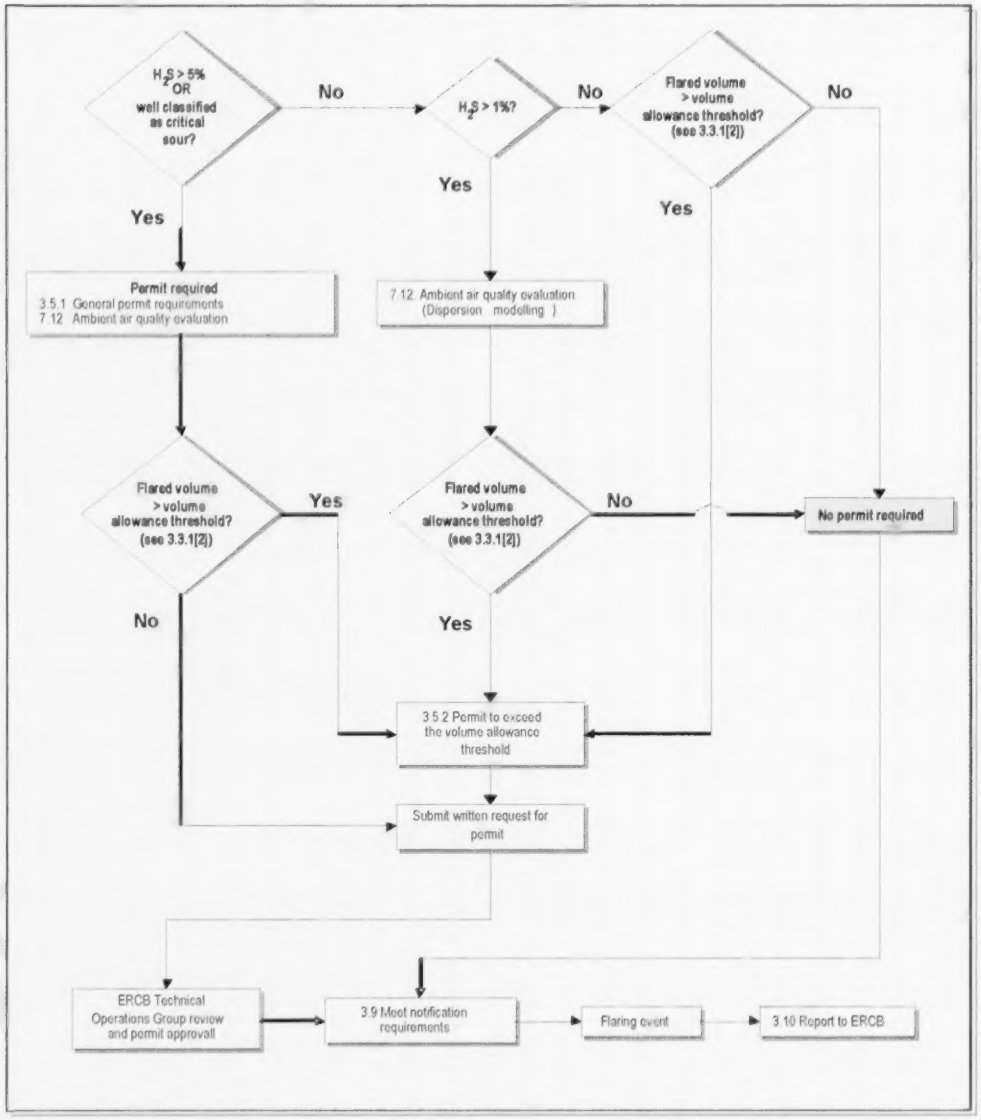

Figure 4. Temporary flaring/incineration permit process

a) The volume allowance threshold is defined in three tiers based on the volume of raw gas flowed back from the well (not including fuel gas added and carbon dioxide [CO_2] or nitrogen used for hydraulic fracturing), regardless of composition. These volumes apply to gas well tests only:

   i) **Tier 1 ≤ 600 10^3 m^3**: applies to wells that have not been tied in and have a Lahee classification of new field wildcat (NFW), new pool wildcat (NPW), deeper pool test (DPT), or outpost (OUT).

   ii) **Tier 2 ≤ 400 10^3 m^3**: applies to wells that have not been tied in and have been assigned a Lahee classification (including development) not listed in the tier 1 allowance (excluding re-entry [REN] and experimental [EX] wells. See (b) and (c) below).

   iii) **Tier 3 ≤ 200 10^3 m^3**: applies to any well that has been tied in to facilities appropriately designed to handle production from the formation being tested (e.g., sweet versus sour service).

   All requested volumes must be justified and may be questioned by the ERCB.

b) The volume allowance threshold for a re-entry well is the same tier allowance (1, 2, or 3) that applied to the well before it was reclassified as re-entry.

c) For wells with a Lahee classification of experimental, the volume allowance threshold is the same tier allowance (1, 2, or 3) that applied to the well before it was reclassified as experimental or that normally would have applied to the well had it not been classified as experimental.

d) An incremental volume of 200 10^3 m^3 may be added to the volume allowance threshold defined above for each additional zone being tested during continuous operations on a well (with continuous operations meaning that servicing equipment and personnel are not demobilized between tests on each zone), subject to the following limitations:

   i) The volume flared from any zone during multiple-zone tests must not exceed the volume allowance threshold for a single zone unless a larger volume is specifically approved by the ERCB Technical Operations Group.

   ii) The incremental allowance does not apply to single tests over multiple commingled zones. Each zone to be tested must be identified and fully accounted for in the related flare permit request.

3.3.2 Conditions That Do Not Require a Temporary Flaring/Incineration Permit

1) A permit is not required if the gas contains 50 mol/kmol H_2S (5 per cent) or less and the total volume (for gas well tests) is less than the volume allowance threshold (see section above). However, licensees must meet the requirements in section 3 and section 7, as well as the notification requirements in section 3.8.

   a) Licensees must evaluate compliance with the one-hour *AAAQO* for SO_2 if the gas contains more than 10 mol/kmol H_2S (1 per cent). Related dispersion modelling results must be provided to the ERCB Technical Operations Group upon request.

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2) Flaring or incinerating small volumes of sour gas containing more than 50 mol/kmol H_2S (5 per cent) are exempt from ERCB permit requirements provided that the following conditions are met:

   a) Instantaneous sulphur emission rates do not exceed 1.0 tonne per day

   b) Total flared or incinerated volume do not exceed 50 10^3 m^3 over the duration of the event

   c) Equipment is designed to ensure compliance with the one-hour *AAAQO* for SO_2 or operating procedures are in place to ensure compliance with the *AAAQO*. Related dispersion modelling evaluations and design information are documented and available to the ERCB Technical Operations Group upon request.

   d) Rates and volumes are measured and reported as defined in section 10.

   e) Written notification is provided to the ERCB Technical Operations Group. Notification includes total expected gas volumes and sulphur emissions. If applicable, notification provides an explanation of any air quality management plans needed to ensure compliance with the *AAAQO*.

3) The ERCB does not require temporary permits for the use of permanent flares or incinerators installed in ERCB-licensed facilities, including batteries, compressor stations, and gas plants provided that licensees can show, on request from the ERCB Technical Operations Group or field centre staff, that

   a) the flaring or incineration volumes, rates, and gas composition are within the limits of the facility licence;

   b) the flares or incinerators are designed to operate safely under the intended conditions in compliance with the *AAAQO*; and

   c) the total volumes are less than the volume allowance threshold.

4) Similarly, the ERCB does not require temporary permits for unplanned nonroutine events such as emergencies. Licensees must ensure that temporary nonroutine systems are adequately designed to operate safely under anticipated emergency and upset conditions and meet the requirements in section 7.

   a) For planned nonroutine events, including maintenance blowdowns, pipeline depressuring, and turnarounds, licensees must obtain a temporary permit if required by section 3.3.1, unless exempted in (2) or (3) above.

5) The ERCB does not require temporary permits for flaring at oil and bitumen batteries. The operator must meet conservation requirements described in section 2.

3.4 Flaring and Incineration Permits for Underbalanced Drilling

Permit requirements (section 3.3) and notification requirements (section 3.8) for temporary flaring and incineration also apply to underbalanced drilling.

For more detail on underbalanced drilling requirements, see *Interim Directive (ID) 94-03: Underbalanced Drilling*, *ID 97-06: Sour Well Licensing and Drilling Requirements*, and appendix 5.

3.5 Permit Requirements for Temporary Flares and Incinerators

Figure 4 summarizes the temporary permit process.

3.5.1 General Permit Requirements

1) Requests for temporary permits must be submitted to the ERCB Technical Operations Group via paper copy and e-mail (Directive060Inbox@ercb.ca) and must include complete information on the proposed activity, as requested in the *ERCBflare.xls* and *ERCBincin.xls* spreadsheets (available on the ERCB website under Regulations & Directives : Directives : Directive 060) and summarized as follows:

   a) a cover letter requesting a permit and informing the ERCB Technical Operations Group of any public objections to or concerns about the proposed flaring/incineration

   b) information about the site on which flaring/incineration will occur, including location, Lahee classification, and related National Topographical System 1:50 000 scale maps

   c) an evaluation of the most feasible option for in-line testing

   d) information on planned flaring/incineration, including reasons (e.g., well testing, completions, pipeline depressuring), H_2S content, flow rates, total volumes, and type of combustion device to be used (i.e., flare or incinerator)

   e) information on the licensee's assessment of effects on ambient air quality, including results of dispersion modelling for SO_2

   f) in situations with potential to exceed the risk-based criteria (see section 7.12.4) for SO_2, information on the licensee's proposed air quality management plan to prevent exceedances

2) Any inconsistencies in the request or modelling will result in the request being rejected and returned to the licensee. Permit requests are processed in the order received, and resubmissions will be treated as new permit requests.

3) Temporary permit requests can be submitted electronically by the licensee. A permit will be in the name of the licensee.

3.5.2 Requests to Exceed the Volume Allowance Threshold

Information requirements apply to all requests to exceed the volume allowance threshold. However, any volume of gas flared or incinerated must be defensible.

1) Licensees must provide specific engineering, economic, and operational information to justify flaring or incinerating gas volumes in excess of the volume allowance threshold.

2) All requests for volumes greater than the volume allowance threshold regardless of H_2S content must be submitted to the ERCB Technical Operations Group (e-mail Directive060Inbox@ercb.ca) and must include the following, in addition to information in section 3.5.1 (note that 1)e) and f) of that section do not apply to sweet gas wells).

   a) Requests relating to tests to determine if enough gas supply exists to justify related investments must include information on the scope of development required to produce the well and necessary threshold reserves. (See appendix 5).

   b) Requests relating to tests to determine the relationship between absolute open flow (AOF) and deliverability of the well must include justification of the volume being

requested as it pertains to obtaining an accurate deliverability relationship, in accordance with ERCB *Directive 040*.

c) Requests relating to tests to establish the stabilized flow rate of the well must include justification of the flare volume request as it pertains to obtaining a stabilized flow rate, including identification of any analogous wells being used for comparison purposes.

3) Should the information described above not be available or applicable, licensees must include discussion on why it is not included with the exceedance request.

4) For underbalanced drilling, follow the guidelines in appendix 5.

3.5.3 Blanket Flaring/Incineration Permits

Sour oil and gas well operations such as well servicing may result in flaring of relatively small volumes of gas at several sites in a local area. To simplify temporary permit request requirements, the ERCB Technical Operations Group may issue a single "blanket" permit to cover several flaring events at different sites in an area if so requested by the licensee. Blanket permit request requirements and limitations are as follows:

1) Blanket permits are issued on a fixed-term basis for periods not to exceed one calendar year. Licensees must complete and submit a new flare permit request to renew blanket permits for additional periods of time.

2) Blanket permits are limited to specific stack heights, locations, rates, maximum volumes per event, maximum H_2S concentrations, and maximum sulphur emissions per event as listed in the permit request.

3) All wells must be licensed before they can be considered for a blanket permit.

4) For every well being considered for a blanket permit, licensees must use the *ERCBflare.xls* or *ERCBincin.xls* spreadsheet (available on the ERCB website under Industry Zone : Rules, Regulations, Requirements : Directives : Directive 060) to evaluate the temporary flaring or incineration parameters during the period in which flaring/incineration is planned.

   a) The spreadsheets provide screening modelling. Refined modelling may be required and must meet the risk-based criteria.

   b) Any inconsistencies in the request or modelling will result in the request being rejected and returned to the licensee.

5) A blanket permit will not be considered if

   a) projected volumes are greater than 100 10^3 m^3 per site or flaring event;

   b) total sulphur emissions will exceed 10 tonnes per event;

   c) an air quality management plan is necessary for compliance with the risk-based criteria for SO_2; or

   d) complex terrain modelling is required for specific locations.

   Exceptions may be made only after consultation with the ERCB Technical Operations Group.

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6) A list of wells and their bottomhole and surface locations and licence numbers must be submitted to the ERCB Technical Operations Group before a blanket permit request will be considered.

7) A sour gas flaring/incineration data summary report (see appendix 6) for each well must be completed and submitted to the ERCB Technical Operations Group within 30 days of the end of each calendar quarter-year.

   If no flaring or incineration was done over the previous calendar quarter-year, a sour gas flaring/incineration data summary report on the lack of flaring or incineration must be submitted.

8) Licensees must comply with public and ERCB field centre notification requirements for each flare event covered by the blanket permit, as described in section 3.8.

3.5.4 ERCB Review of Permit Requests

Requested volumes, rates, or conditions may not be granted by the ERCB Technical Operations Group. Consideration will be given to total volumes, total sulphur emissions, local land uses, proximity of residences, and potential for exceedance of the *AAAQO* before a permit is granted. ERCB Technical Operations Group staff will consult with licensees in such situations.

1) Licensees must avoid temporary flaring or incineration in situations where existing infrastructure can be reasonably used for in-line disposition of the gas, especially in populated areas.

2) Licensees must limit the volumes for gas that they request, especially gas with high H_2S contents. Situations involving sulphur emissions of 50 tonnes or more are subject to closer scrutiny by the ERCB Technical Operations Group. The ERCB Technical Operations Group typically will not approve permits where total sulphur emissions exceed 300 tonnes.

3.6 Site-Specific Requirements Related to Well Flaring and Incineration

The following requirements apply to the use of temporary flares and incinerators.

1) Temporary flares and incinerators must comply with design and operation requirements defined in section 7.

   a) Flares and incinerators must not be operated outside design operating ranges as specified by the designing or reviewing qualified technical professional who is a member of the Association as defined in the *Engineering and Geoscience Professions Act*[10].

2) Licensees must determine the H_2S content of flared or incinerated gas using Tutweiller or gas chromatography methods as soon as is practical after beginning operation if gas analysis has not been done within the preceding 12 months.

3) If the H_2S content in the gas is found to exceed 50 mol/kmol H_2S and no flaring or incineration permit has been issued by the ERCB Technical Operations Group, or if the H_2S content of the gas exceeds the maximum value listed in the related permit,

[10] *Engineering and Geoscience Professsions Act*, RSA 2000 c. E-11, as amended

operations must be suspended and the appropriate ERCB field centre notified. Operations must not resume until a permit or permit amendment is issued by the Operations Group in response to a written request.

4) Both high- and low-pressure gas-liquid separation stages must be used for sour gas to minimize vapour released from produced hydrocarbon liquid and sour water storage.

5) Liquid storage must be designed to prevent the escape of sour gas to the environment. For more detail, see the most current edition of *Industry Recommended Practice [IRP] Volume 4: Well Testing and Fluid Handling* from the Canadian Petroleum Safety Council.

3.7 Temporary Facilities for In-Line Tests

To facilitate conservation, the licensee or operator may install a temporary compressor and pipeline connections. For temporary compressor installation, see *Directive 056*.

Section 3.7 of this directive does not apply to oil batteries. However, *Directive 056* application requirements apply to both temporary and permanent oil batteries.

1) Details on application requirements and exceptions for temporary well test facilities and pipeline connections are in *Directive 056*. In the case of a discrepancy between this directive and *Directive 056*, *Directive 056* application requirements apply.

2) Exceptions to ERCB applications requirements for temporary facilities, such as temporary connection to existing gathering systems, are intended to encourage conservation of gas associated with well testing. The provisions do not apply to testing situations in which gas will be flared.

3) Only one test period will be approved at each site. If there are multiple events, an application is required (see *Directive 056*).

4) For extended tests or multiple tests that require temporary facilities to operate for more than 21 days, the licensee or operator must complete an application (see *Directive 056*).

5) Proposals to install temporary compressors and other facilities for reasons other than testing new wells must comply with *Directive 056* application requirements.

6) Any licensee or operator intending to use temporary production, compression, and/or pipeline facilities must notify the appropriate ERCB field centre and obtain approval for a variance from *Directive 056* application requirements.

   a) The notification must include a description of the proposed equipment (including relevant capacities), driver type, and layout (e.g., give the compressor power rating and note whether the driver type is gas, diesel, or electric).

   b) A licensee or operator intending to install and use temporary pipelines for well testing must complete and submit to the appropriate ERCB field centre the Checklist for 21-Day Temporary Surface Pipelines for Well Testing Purposes.[11]

[11] Available on the *Directive 056* page of the ERCB website www.ercb.ca under Industry Zone : Rules, Regulations, Requirements : Directives.

c) ERCB field centre approvals for temporary facilities are valid for 21 days and include the dismantling and removal of temporary facilities (including pipelines) from the lease. Any exceptions, including allowances for downtime during testing, must be referred to the appropriate ERCB field centre for further review.

7) Temporary facilities, including pipelines, must comply with relevant ERCB requirements.

a) Temporary facilities must meet noise control requirements defined in *Directive 038: Noise Control*.

b) The licensee or operator must meet emergency response plan requirements for sour wells. The plan must incorporate provisions for the temporary equipment, as appropriate. See *Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry*.

8) Temporary sweetening processes, if used, must be of the zero-sulphur-emissions type. The licensee or operator must submit a facility application, as described in *Directive 056*, for temporary installation of regenerative sweetening processes with acid gas.

a) All temporary or permanent regenerative sweetening facilities require an ESRD sour gas processing plant approval.

9) Temporary pipelines and batteries must comply with *Directive 056* public consultation requirements.

3.8 Notification Requirements

The licensee, operator, or approval holder must provide notice of flaring, venting, or incineration in accordance with this directive. The ERCB does not require the licensee, operator, or approval holder to obtain the consent of residents within the notification radius.

1) The licensee, operator, or approval holder must notify all residents of flaring, incineration, and venting in accordance with. The notification distances in are minimum requirements.

2) Notice must be given to the appropriate ERCB field centre via the DDS system of any planned flaring, incineration, or venting at least 24 hours in advance.

a) Notice to the appropriate ERCB field centre must include a contact name and telephone number in case of complaints or emergencies.

3) Upon ERCB field centre request, the licensee, operator, or approval holder must provide a list of notified residents who live within the specified notification radius, as well as a sample of the information provided to residents.

4) The licensee, operator, or approval holder must notify residents in writing (see appendix 9) and include the following basic information about the flaring, incineration, or venting:

a) the licensee, operator, or approval holder's name, contact persons, and telephone numbers

b) the location of the flaring, incineration, or venting

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c) the duration of the event (start date and latest expected completion date, including flowback operations)

d) the expected event volume and rates

e) information on the type of well (oil, gas, or coalbed methane) and, if applicable, information on the H_2S content of the flared or incinerated gas

f) ERCB field centre contact telephone number

Table 2. Temporary flaring, venting, and incineration notification requirements[1,2]

Type of operation (applies to sweet and sour streams)	Duration of event (hrs in 24-hr period)		Gas volume ($10^3 m^3$ in a 24-hr period)	Notification[3]
Temporary (i.e., for well cleanup, testing, or maintenance)	< 4	and	< 30	No notification[4]
Temporary (i.e., for well cleanup, testing, or maintenance) if gas contains ≤ 10 mol/kmol H_2S	> 4	or	> 30	Residents, 1.5 km radius; ERCB field centre
Temporary (i.e., for well cleanup, testing, or maintenance) if gas contains >10 mol/kmol H_2S	> 4	or	> 30	Residents, 3 km radius; ERCB field centre
Temporary (i.e., for well cleanup, testing, or maintenance) through permanent battery or plant flare or incinerator	< 4		–	No public notification;[4] Notify ERCB[5] if flaring >30 10^3 m^3
Temporary (i.e., for well cleanup, testing, or maintenance) through permanent battery or plant flare or incinerator	> 4		--	Residents, 0.5 km radius;[5] ERCB field centre

[1] Temporary venting is not permitted within 500 m of a residence unless consented to by the resident and approved by the ERCB field centre (section 8.1[6]).

[2] See section 1.6 for information on the ERCB DDS system and how to notify the appropriate ERCB field centre via DDS.

[3] 24 to 72 hours in advance of planned flaring, venting, or incineration operations, the licensee, operator, or approval holder must notify the appropriate ERCB field centre via the DDS system, all rural residents outside towns, villages, and urban centres and within the specified radius, and the chief administrative officer or equivalent of a town, village, or urban centre within the specified radius. Note that for incorporated centres and hamlets, it is sufficient to contact only the appropriate administrator. Advance notification of more than 72 hours (not longer than 90 days) must also offer the option for renotification within the 24- to 72-hour period before operations. After 90 days, renotification is mandatory.

[4] The ERCB recommends additional "good neighbour" notification for short-duration events for residents who have identified themselves to the licensee, operator, or approval holder as being sensitive to or interested in emissions from the facility within the same notification radius as specified for events of more than four hours.

[5] The ERCB recommends additional "good neighbour" notification for longer duration events (of more than four hours) for residents who have identified themselves to the licensee, operator, or approval holder as being sensitive to or interested in emissions from the facility.

* Notification requirements include duration and volume from flowback operations. Note that reported volumes must distinguish between volumes from flared hydrocarbon gas to surface and volumes from vented nitrogen or carbon dioxide in fracturing fluid.

5) The licensee, operator, or approval holder may conduct a one-time notification program for multiple-well projects in an area. In addition to the information above, the related multiple-well project notification must provide

a) the locations where flaring, incineration, or venting will occur,

b) the period during which the project will be carried out, and

c) the expected duration and volume of temporary flaring, venting, or incineration.

6) The licensee, operator, or approval holder may limit the number of repeat notifications to individual residents if

   a) the resident requests that the number of notifications be reduced;

   b) the licensee, operator, or approval holder provides the resident with an outline of expected flaring and incineration activities in the area; and

   c) the licensee, operator, or approval holder documents a written agreement to reduce notifications and get the signatures of the residents to ratify the agreement. A copy of this letter agreement must be provided to the ERCB upon request.

7) The licensee, operator, or approval holder may conduct a single notification to each resident within the notification area and the appropriate ERCB field centre, rather than a separate notification for each flaring, venting, or incineration period throughout the program, if this is acceptable to the potentially affected parties. The method of notification must be discussed during the initial notification process.

8) The ERCB recommends that the licensee, operator, or approval holder consider placing signage on public roads surrounding the temporary flaring or incineration operations indicating the operation type and the contact phone number for inquiries.

3.8.1 Addressing Resident Concerns

Compliance with *Directive 060* ensures that licensees, operators, and approval holders have considered public safety and environmental impacts before flaring, incineration, and venting activities; however, additional concerns or complaints may be expressed by nearby residents regarding impacts of the operational aspects of flaring or incineration (e.g., timing of flaring and associated traffic). The following ensure that concerns of nearby residents are addressed:

1) The ERCB encourages the licensee, operator, or approval holder to work with nearby residents prior to commencing proposed and existing flaring or incineration activities.

2) The licensee, operator, or approval holder must immediately disclose any unresolved concerns of nearby residents about those activities to the appropriate ERCB field centre in order to discuss concerns or complaints related to those activities.

3) Residents may subsequently contact the appropriate ERCB field centre to discuss concerns or complaints related to those activities.

The ERCB may work further with the licensee, operator, or approval holder to modify one or more operational aspects of the proposed or existing flaring or incineration activities to address nearby resident concerns, but it will not suspend flaring or incineration activities in response to a concern or complaint unless there is clear evidence that the licensee, operator, or approval holder is not in compliance with *Directive 060*.

3.8.2 ERCB Flaring/Incinerating/Venting Notice Form

1) To comply with the requirements in section 3.8 above, the licensee, operator, or approval holder must complete the ERCB flaring/incineration/venting notice form in the DDS system and submit it electronically to the appropriate ERCB field centre.

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3.9 Reporting Gas Well Test Data

1) Well test results and information required by flaring and incineration permits must be submitted in accordance with the requirements of *Directive 040: Bulletin 2004-15: New Well Test Capture (WTC) System Implementation Date Reminder Changes to Final WTC Pressure ASCII Standard (PAS) Formats and Version 4.0 PAS File Business Rules Implications*; the applicable permit; and section 10.

   a) All well test reports must be submitted within three months of completing the fieldwork. This information must include the volume of gas produced to flare, vent, or pipeline, as well as all gas analyses from samples gathered at the wellhead. Submissions must be in a pressure ASCII standard (PAS) format and submitted via the well test data capture system in DDS. For questions on these submissions, e-mail the well test helpline at Welltest-Helpline@ercb.ca.

2) For all well tests that require permits, a sour gas flaring/incineration data summary report must be submitted to the ERCB Technical Operations Group within three weeks of the completion of flaring or incineration (see section 10.4, appendix 6, and *ERCBflare.xls* or *ERCBincin.xls* spreadsheet).

3) All flaring, incineration, and venting at a well site (including well tests) must be reported on the appropriate production reporting submissions, including PETRINEX (see *Directive 007: Volumetric and Infrastructure Requirements*).

   a) In order to be able to report to the ERCB, the licensee, operator, or approval holder must obtain a battery code. Any produced volumes, including those flared, incinerated, or vented, must be reported (see *Directive 007*).

   b) Fluid volumes and fuel consumption must be recorded and reported on the monthly production submissions (see section 10).

3.10 Zero Flaring Agreements

Flaring is allowed by the ERCB when done in accordance with *Directive 060*. However, parties may agree to zero flaring, as set out in a zero flaring agreement (see appendix 10). The agreement must be signed by both parties and filed by the applicant with the well application. Once filed, the zero flaring agreement becomes a condition of the well licence. Should the licensee, operator, or approval holder fail to adhere to this agreement, operations at the well may be suspended. This agreement, including the condition, expires when production begins.

Once the well or facility is licensed, if the licensee, operator, or approval holder needs to change this zero flaring agreement, it must file an application to change the agreement with the ERCB Technical Operations Group, with a copy to the co-signers.

1) An application to change a zero flaring agreement must include

   a) the reasons that the agreement needs to be changed,

   b) a copy of the original application and approval,

   c) a copy of the original and revised zero flaring agreement, and

   d) a summary of the consultation and notification that have been done, including confirmation of agreements reached with the parties affected by this agreement.

Until the ERCB decides on this application, flaring may only occur as set out in the zero flaring agreement. For oil wells, agreement not to flare during well testing means that the licensee, operator, or approval holder has agreed to initially conserve the gas. Later, if it becomes uneconomic to conserve the gas, the licensee, operator, or approval holder must follow the process in section 2.6(6) of this directive to discontinue conservation.

The licensee, operator, or approval holder must try to address the landowner or occupant concerns and may use the ERCB's appropriate dispute resolution process[12] if that becomes necessary before applying with the ERCB to change this zero flaring agreement.

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[12] See ERCB Informational Letter (*IL*) *2001-1: Appropriate Dispute Resolution (ADR) Program and Guidelines for Energy Industry Disputes* for more information.

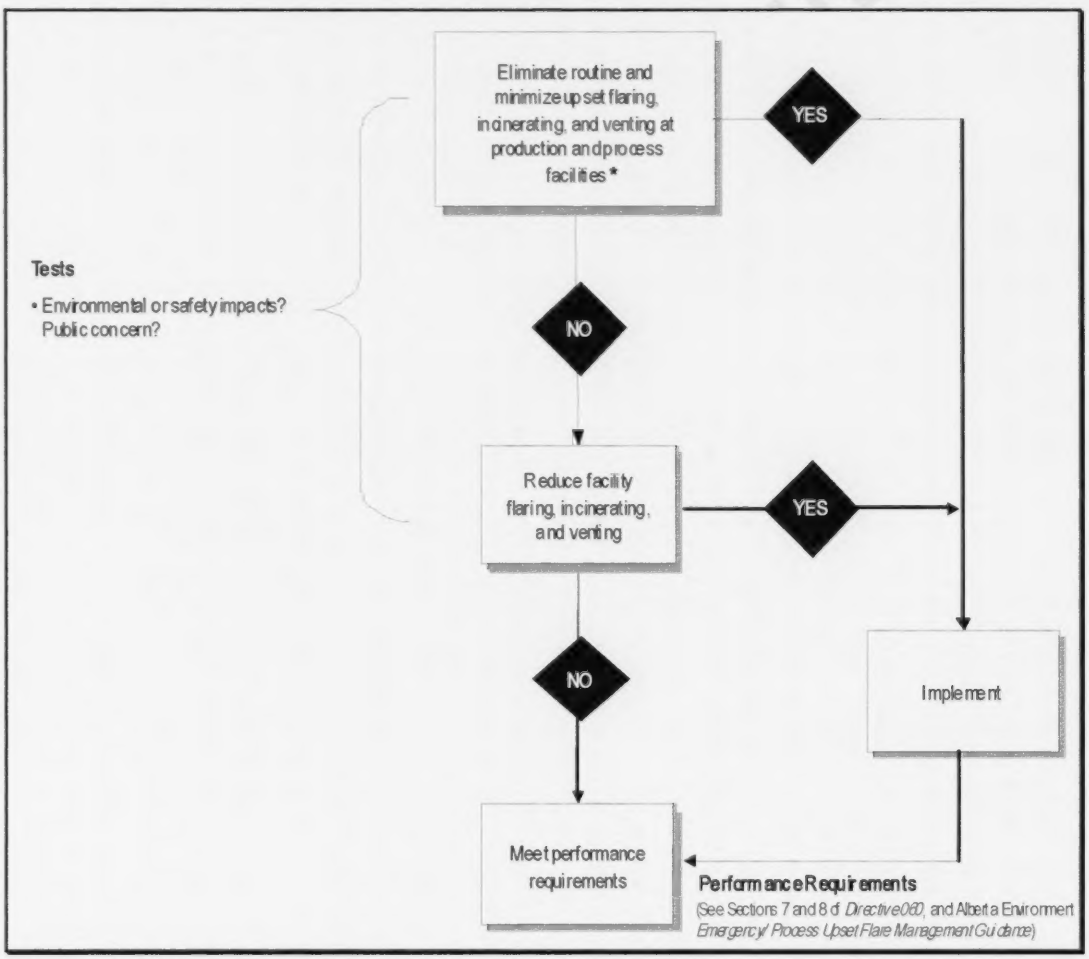
4 Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting

This section addresses gas battery, dehydrator, and compressor station flaring, incinerating, and venting and includes

- routine flaring and incineration, and
- nonroutine flaring, incineration, and venting for equipment depressuring for maintenance; process upsets; and emergency depressuring for safety reasons.

4.1 Gas Battery, Dehydrator, and Compressor Station Flaring, Incinerating, and Venting Decision Tree

1) The licensee or operator must use the decision tree analysis shown in figure 5 to evaluate all new and existing gas battery, dehydrator, and compressor station flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m^3 per month) such as pig trap depressuring.


Eliminate routine and minimize upset flaring, incinerating, and venting at production and process facilities *
YES
Tests
• Environmental or safety impacts? Public concern?
NO
Reduce facility flaring, incinerating, and venting
YES
NO
Implement
Meet performance requirements
Performance Requirements
(See Sections 7 and 8 of Directive 060, and Alberta Environment Emergency/ Process Upset Flare Management Guidance)

* This does not apply to emergency situations.

Figure 5. Facility flaring, incinerating, and venting decision tree (adapted from CASA)

2) The licensee or operator must document alternatives that were considered in order to eliminate or reduce flaring, incineration, and venting, how they were evaluated, and the outcome of the evaluation.

3) New batteries proposing routine flaring, venting, or incineration must be evaluated before application as part of the facility design. All existing batteries with routine sources were required to have been evaluated by December 31, 2004.

4) The licensee or operator must assess opportunities to eliminate or reduce nonroutine flaring, incineration, and venting of gas due to frequent (i.e., one event per month) maintenance or facility shutdowns.

   a) The licensee or operator must investigate and correct frequent nonroutine events at gas batteries.

   b) The licensee or operator must address concerns or objections of residents related to nonroutine gas battery flaring.

5) Flare, incinerator, and vent systems must be designed and operated in compliance with sections 7 and 8, good engineering practice, and relevant safety codes and regulations. All permanent flare stacks installed before January 1, 2000, were required to have implemented the results of the decision tree evaluation by December 31, 2004.

4.2 Notification

1) The licensee or operator must notify residents and the appropriate ERCB field centre of nonroutine flaring at gas batteries as follows:

   a) If gas battery flaring exceeds four hours in duration, the licensee or operator must notify residents as described in section 3.8 and table 2.

   b) If a gas battery flaring event exceeds 30 10^3 m^3 and/or four hours in duration or is likely to cause resident concern, the appropriate ERCB field centre must be notified (see table 2). If *Directive 060* notification requirements differ from those of *IL 98-01*, the licensee or operator must comply with the more stringent requirement.

2) The licensee or operator must give the ERCB field centre at least 24 hours notice of planned gas battery outages and turnarounds that will result in flaring of more than 30 10^3 m^3 or for more than four hours duration.

4.3 Reporting

1) All monthly flared, incinerated, and vented volumes must be reported separately on PETRINEX in accordance with section 10 and *Directive 007*. Incinerated volumes must be combined with and reported as flared volumes.

2) Gas burned in an incinerator must be reported as flared. Fuel gas burned in an incinerator must be reported as fuel gas.

3) Gas flared or vented at gas batteries must be reported at the flaring or venting location. For facilities that do not require a licence (such as small booster compressors), the flared and vented volumes must be reported at the nearest upstream reporting well, battery, or pipeline facility.

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5 Gas Plant Flaring, Incinerating, and Venting

This section addresses disposal of gas from gas processing plants by flaring, incinerating, and venting. Sources of natural gas flaring, incineration, and venting at gas production facilities include

- routine flaring, incineration, and venting of low-pressure flash gas and other gas streams, and
- nonroutine flaring, incineration, and venting for equipment depressuring for maintenance process upsets, and emergency depressuring for safety reasons.

5.1 Gas Plant Flaring, Incinerating, and Venting Decision Tree

Licensees must use the decision tree analysis shown in figure 6 to evaluate all new and existing gas plant flares, incinerators, and vents regardless of volume except for intermittent small sources (less than 100 m^3 per month) such as pig trap depressuring. Furthermore, these evaluations must be updated annually or when changes at the plant materially change plant operation.

1) Licensees must document alternatives that were considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation.

2) Licensees must assess opportunities to eliminate or reduce nonroutine flaring, incineration, and venting of gas due to frequent maintenance or facility reliability outage, as well as

   a) address concerns and objections of residents notified in accordance with table 2 related to nonroutine flaring, and

   b) comply with the limitations on total flared, incinerated, and vented volumes and the number of repeat events defined in sections 5.2 and 5.3.

3) Flare, incinerator, and vent systems must be designed and operated in compliance with sections 7 and 8, good engineering practice, and any other safety codes and regulations required by other agencies.

   a) Gas streams directed to continuous gas plant flares must have a minimum heating value as defined in section 7.1.1.

   b) All existing plants were required to have performance evaluations completed by December 31, 2004.

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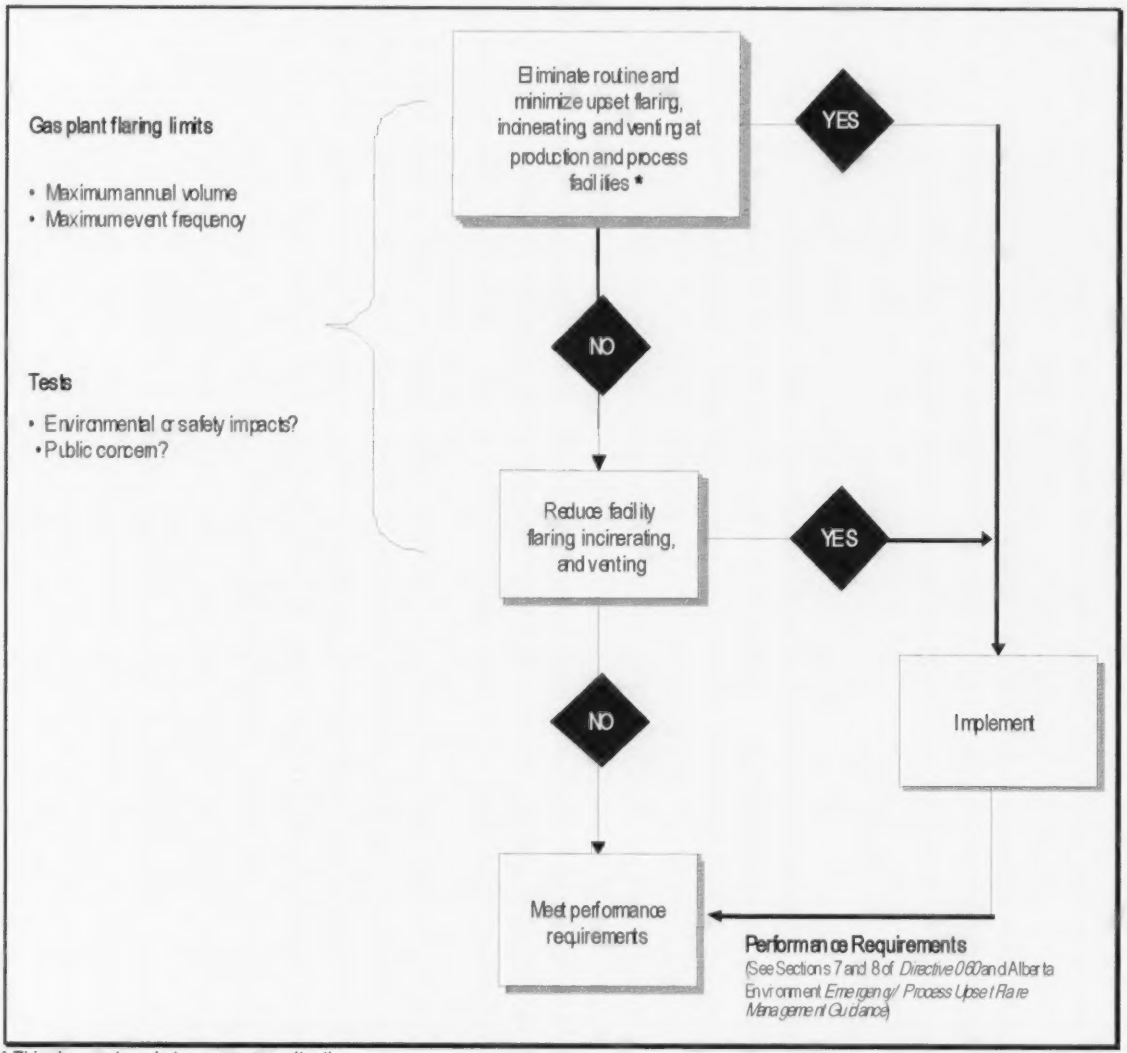
Gas plant flaring limits
• Maximum annual volume
• Maximum event frequency
Tests
• Environmental or safety impacts?
• Public concern?
Eliminate routine and minimize upset flaring, incinerating, and venting at production and process facilities *
YES
NO
Reduce facility flaring incinerating, and venting
YES
NO
Implement
Meet performance requirements
Performance Requirements
(See Sections 7 and 8 of Directive 060 and Alberta Environment Emergency/ Process Upset Flare Management Guidance)

* This does not apply to emergency situations.

Figure 6. Facility flaring, incinerating, and venting decision tree (adapted from CASA)

5.2 Gas plant flaring/incineration/venting volume limits

The ERCB limits the total annual volume of gas disposed of by flaring, incineration, and venting at gas processing plants. Fuel gas used for pilots or flare system purge and acid gas volumes from gas sweetening (which are normally continuously flared) are excluded from the following limits:

1) For gas plants processing less than 1.0 billion (10^9) m^3 per year (raw gas inlet volume), flaring, incineration, and venting must not exceed 1 per cent of raw gas receipts in the first year of operation and must not exceed 0.5 per cent of receipts in any subsequent year.

2) For gas plants processing more than 1.0 10^9 m^3 per year, flaring, incineration, and venting must not exceed the greater of 0.2 per cent of receipts or 5.0 10^6 m^3 per year.

3) If multiple flare stacks are available in gas production, gathering, and processing systems, licensees must use the flare stack that is the most efficient and capable of providing the best dispersion. In most cases this would be the gas plant flare stack.

   a) Licensees can deduct solution gas flared at gas plants during plant shutdowns lasting more than seven days in calculating the annual flared volumes applicable to (1) and (2) above. These solution gas volumes must be documented and provided to the ERCB upon request.

4) Licensees must comply with the solution gas reduction limitations in section 1 during facility outages.

5) All nonassociated gas must be shut in during facility outages.

6) The ERCB recommends that solution gas processing take priority over the processing of nonassociated gas.

5.3 Frequent Nonroutine Flaring/Incineration/Venting Events

Information on enforcement actions for not meeting the criteria below is provided in section 12.

1) Licensees must investigate and correct causes of repeat nonroutine flaring, incineration, and venting.

2) Gas plants must not exceed six major nonroutine flaring events in any consecutive (rolling) six-month period (6-in-6). Major flaring events are defined in Table 3.

Table 3. Major flaring event definition

Approved plant inlet capacity	Major flaring event definition*
> 500 10^3 m^3/d	100 10^3 m^3 or more
150–500 10^3 m^3/d	20 per cent of plant design daily inlet or more
< 150 10^3 m^3/d	30 10^3 m^3 or more

* The definition of a flaring event includes situations where

1) volumes greater than or equal to those specified in the table are flared in any single day; each day that specified flared volumes are exceeded is considered to be a separate, individual event; or
2) volumes greater than or equal to those specified in the table are flared in one contiguous period spanning more than one day (e.g., flaring for four days at a continuous rate of 25 10^3 m^3/d is considered one event).

1) Licensees must log and monitor nonroutine flaring events, as required in section 10.4. Major flaring events must be flagged. The following applies if a sixth major flaring event occurs within any consecutive (rolling) six-month period:

   a) Licensees must submit a written "exceedance" report to the appropriate ERCB field centre and copy this report to the ERCB Technical Operations Group within 30 days of the occurrence of the sixth flaring event.

      i) The exceedance report must provide data on all flaring events (volume and duration) for the consecutive (rolling) six-month period in question and on their possible causes.

      ii) The report must also propose a plan and corresponding timeline for implementing corrective actions to ensure that frequent major nonroutine flaring does not recur.

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b) Licensees must obtain ERCB field centre approval of the proposed plan referred to in 3(a)(ii) above.

i) If facility modifications are proposed in the plan and approvals are required by *Directive 056*, ERCB Applications Group approval must be obtained before implementing any such actions.

ii) Upon ERCB field centre approval of the plan, including facility modifications, licensees are expected to expedite schedules for implementing the plan.

c) After the plan implementation date, the ERCB will take enforcement action if another exceedance of the 6-in-6 criterion occurs within 24 months.

5.4 Notification

1) Licensees must notify residents and the appropriate ERCB field centre of nonroutine flaring at gas plants (see table 2).

a) The appropriate ERCB field centre must be notified if a nonroutine flaring event exceeds 30 10^3 m^3, exceeds four hours' duration, or is likely to cause public concern.

b) If more stringent notification requirements than required by this directive have been put in place through *IL 98-01: A Memorandum Of Understanding Between Alberta Environmental Protection And The Alberta Energy And Utilities Board Regarding Coordination Of Release Notification Requirements And Subsequent Regulatory Response*, licensees must comply with the more stringent requirements.

c) Licensees must provide the appropriate ERCB field centre with at least 24 hours' notice of a plant turnaround.

d) The appropriate ERCB field centre must be notified 24 to 72 hours before planned flaring and within 24 hours of unplanned flaring when notification is required.

5.5 Measurement and Reporting

Measurement and reporting requirements for gas plants include the following:

1) All monthly flared and vented volumes must be reported separately on PETRINEX (see section 10) in accordance with *Directive 007*.[13] Incinerated volumes must be reported as "flared."

2) Flaring of sour gas must also be reported on the S-30 Monthly Gas Processing Plant Sulphur Balance Report (see section 11 of *Directive 017*).

3) When measurement is not required, engineering estimates must be used to report any flared gas not measured (see section 10).

4) Licensees must provide a documented system for measurement and/or estimation of flared and vented gas volumes (as defined in section 10) upon ERCB Technical Operations Group request. All flare events both minor and major must be logged (in accordance with section 10.4) and provided upon request.

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[13] This information is summarized annually in ERCB *ST13A: Alberta Gas Plant/Gas Gathering System Activities—Annual Statistics* and monthly in *ST13B:Alberta Gas Plant/Gas Gathering System Activities—Monthly Statistics* and *ST13C: Alberta Gas Gathering System Activities—Monthly Statistics*.

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5) Fuel gas that is flared, incinerated, or vented (e.g., flare pilot gas, header purge gas, storage tank blanket gas) must be reported as fuel gas, not flared gas.

6) Licensees must monitor and minimize fuel gas use for flare header purge, flare, and incinerator pilots.

   a) Licensees must be able to justify fuel gas usage volumes.

   b) The ERCB may require evidence of this justification on the basis of case-specific audits and inspections.

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6 Pipeline Flaring, Incinerating, and Venting

This section addresses disposal of gases from gas gathering and transmission lines by flaring, incineration, and venting. Sources of gas flaring, incineration, or venting include

- routine flaring, incineration, and venting of low-pressure flash-gas and other gas streams at pipeline system compressor and dehydration facilities, and
- nonroutine flaring, incineration, and venting for pipeline depressuring for maintenance, process upsets, or emergency depressuring for safety reasons.

6.1 Pipeline Systems Flaring, Incineration, and Venting Decision Tree

Licensees must use the decision tree analysis shown in figure 7 to evaluate all new and existing pipeline systems, including compression station flares, incinerators, and vents, except for intermittent small sources (less than 100 m^3 per month) such as pig trap depressuring. These evaluations must be updated before any planned flaring, incinerating, or venting.

1) Licensees must document alternatives considered in order to eliminate or reduce flaring, incineration, or venting, how they were evaluated, and the outcome of the evaluation.

2) Licensees must assess opportunities to eliminate or reduce flaring, incineration, and venting of gas due to frequent maintenance or facility outage as follows:

   a) Investigate and correct repeat events at gas pipelines and related facilities (e.g., compressor stations).

   b) Address public complaints and concerns about pipeline facility flaring, incineration, or venting.

   c) Investigate and implement feasible measures to conserve gas from the depressuring of pipeline systems.

3) Licensees of gas pipeline systems must ensure that flares, incinerators, and vents are designed and operated in compliance with sections 7 and 8, good engineering practices, and all relevant safety codes and regulations.

4) The sulphur recovery requirements of section 9 and *ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta* apply to any continuous flaring or incineration of sour gas at gas gathering facilities (e.g., compressor or dehydrator sites).

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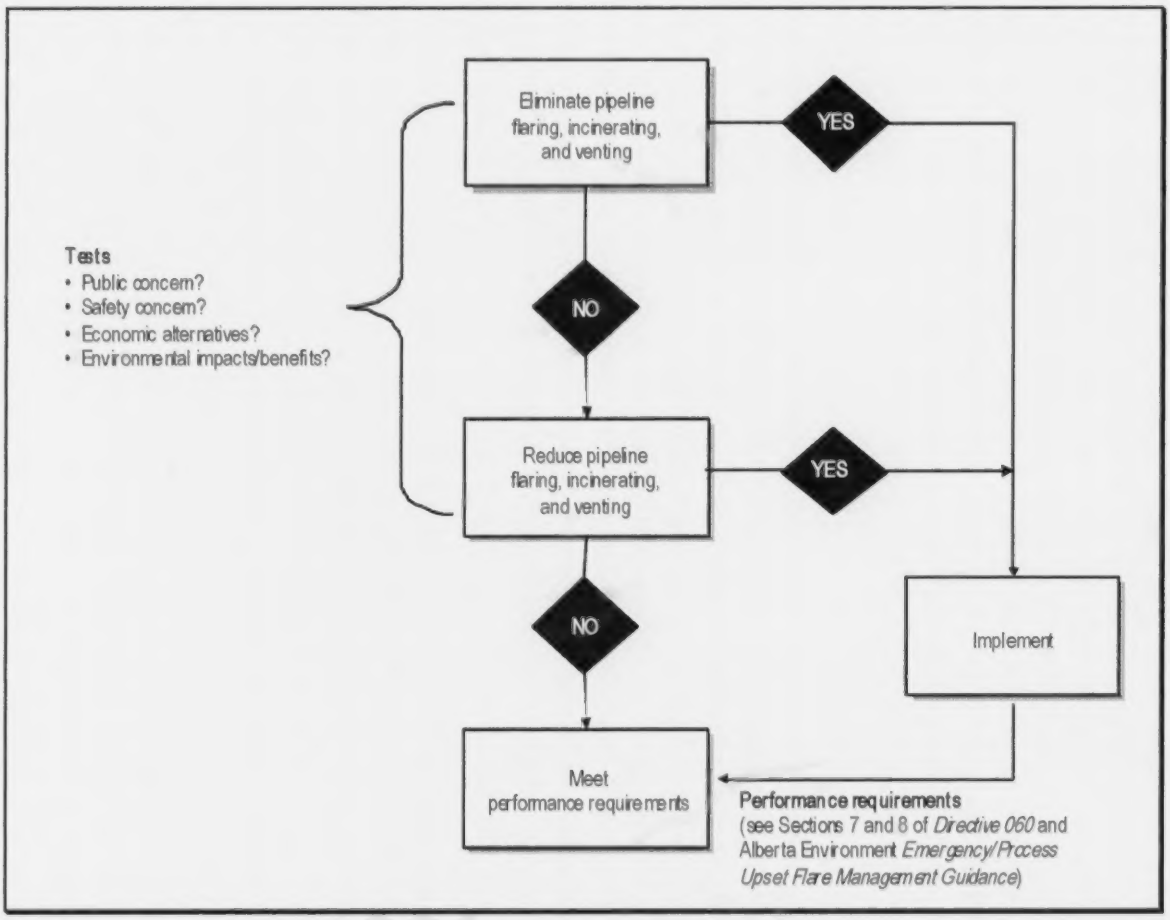

Figure 7. Pipeline flaring, incinerating, and venting decision tree (adapted from CASA)

6.2 Additional Requirements for Gas Gathering Systems

1) All monthly flared, incinerated, and vented volumes must be reported separately on PETRINEX in accordance with section 10 and *Directive 007*. Incinerated volumes must be combined with, and reported as, flared volumes.

2) Gas containing more than 5 parts per million (ppm) H_2S must not be released from a pipeline without the approval of the ERCB unless the gas is burned such that it meets the requirements in section 7.

   - Flaring or incineration of gas must meet the requirements in section 7.
   - Venting of gas must meet the requirements in section 8.

3) Licensees must get an ERCB temporary flaring/incineration permit in order to use temporary flares or incinerators for the disposal of sour gas containing more than 50 mol/kmol (5 per cent) H_2S, as described in section 3.3.

   a) Permits are not required for disposal of small amounts of sour gas if the requirements defined in section 3.3.2 are met.

b) Permit request requirements (section 3.5) apply to temporary flares and incinerators used for sour gas pipeline depressuring, except in emergencies.

4) Notification requirements described in apply.

6.3 Natural Gas Transmission Systems

This directive applies to flaring, incineration, and venting in conjunction with natural gas transmission systems, subject to the following provisions:

1) Licensees of sweet natural gas transmission pipelines must minimize venting, flaring, and incineration volumes.

   a) The economic evaluation in section 2.9 does not apply to evaluating conservation of gas from nonroutine pipeline depressuring for maintenance.

   b) When evaluating conservation of gas from planned nonroutine pipeline depressuring, licensees must consider the value of gas, the costs of conserving the gas, and the economic effects of extending outages on downstream customers and upstream producers.

2) Flaring or incineration of gas from sweet natural gas transmission pipeline depressuring may not be practical when impacts on system customers and producers are considered. In such situations, the appropriate ERCB field centre may allow the venting of gas to reduce the duration of system outages and related impacts.

6.4 Notification

1) Licensees must notify residents and the appropriate ERCB field centre of nonroutine flaring, incineration, or venting at licensed gas pipeline facilities as follows:

   a) If pipeline facility flaring, incineration, or venting exceeds four hours in duration or 30 10^3 m^3, licensees must notify as specified in section 3.8 and table 2.

   b) In areas where more stringent notification requirements than those defined in table 2 are required by *IL 98-01* or through other regulatory requirements, licensees must comply with the more stringent requirements.

2) Licensees must provide the appropriate ERCB field centre with at least 24 hours notice of planned pipeline facility outages that will result in flaring, incineration, or venting.

3) When nonroutine pipeline flaring, incineration, or venting is planned, licensees of sweet natural gas transmission pipelines must notify the appropriate ERCB field centre and discuss the measures taken to minimize emissions.

4) Each purchaser or transporter of sweet natural gas must report the particulars of the disposition and delivery of its gas to the ERCB monthly (see section 12.051 of the *Oil and Gas Conservation Regulations* [*OGCR*]).

   a) Flared and vented volumes of sweet natural gas must be reported separately. Incinerated volumes must be combined with, and reported as, flared volumes.

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7 Performance Requirements

These requirements apply to flares and incinerators in all upstream oil and gas industry systems for burning sweet, sour, and acid gas, including portable equipment used for temporary operations including well completion, servicing, and testing. Flare and incinerator systems include associated separation equipment, piping, and controls.

For the purposes of this directive, the terms flare and incinerator are used interchangeably except as specifically noted in sections 7.1 and 7.4. In these sections, some requirements are specific to the type of equipment used, and this is specified in those requirements.

Although some design or operating specifications are provided, this directive is not a substitute for comprehensive engineering design codes and guidelines. It identifies minimum ERCB regulatory requirements but is not intended as a comprehensive design manual.

1) The licensee, operator, or approval holder must ensure that a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*[14] is responsible for the design or review of flare and incinerator systems, including separation, related piping, and controls, and for the specification of safe operating procedures.

    a) Equipment and controls design information must be provided to the ERCB upon request if the ERCB determines that there is a concern with the equipment or controls.

2) The licensee, operator, or approval holder must ensure that operating procedures that define the operational limits of flare or incinerator systems are documented and implemented and that these procedures meet the design requirements.

    a) Operating limits and procedures must be provided to the ERCB immediately upon request.

    b) Flare and incinerator systems must be operated within the operational ranges and types of service specified by the designing or reviewing engineer, technician, or technologist. If this equipment is used for emergency shutdowns, this must be considered in the design.

3) If using, in a field service, a flare or incinerator that has not previously been field tested, the licensee, operator, or approval holder must be able to provide actual monitoring data to show that performance specifications will be met.

    a) Field testing of newly designed equipment is not allowed unless there are acceptable and redundant combustion systems to ensure that any sweet, sour, or acid gas can be properly combusted if the new equipment fails to perform as predicted, or unless the facility is capable of being shut in if problems arise.

4) *ANSI API Standard 521: Pressure-Relieving and Depressuring Systems*, as well as applicable fire safety codes, electrical codes, CSA standards, and mechanical engineering standards, are all necessary references for the design of gas combustion systems.

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[14] *Engineering and Geoscience Professsions Act*, RSA 2000 c. E-11, as amended

5) The licensee, operator, or approval holder must comply with Alberta safety regulations with respect to the design of pressure vessels and piping systems and the design of equipment and operating procedures (see *Pressure Equipment Safety Regulation*).

6) The ERCB recommends that all licensees, operators, and approval holders use best engineering practices, as well as appropriate engineering codes and standards, in the design and operation of flare systems.

7.1 Conversion Efficiency

Definitions and calculations for carbon conversion efficiency, sulphur conversion efficiency, and combustion efficiency are in appendix 2.

1) Flares and incinerators and other gas combustion systems, including those using sour gas as a fuel for production or process equipment, must be designed, maintained, and operated so that emissions do not

   a) result in off-lease H_2S odours, or

   b) exceed the *AAAQO*.

2) The licensee, operator, or approval holder must modify or replace existing flares or incinerators if operations result in off-lease odours, odour complaints, or visible emissions (e.g., black smoke).

7.1.1 Heating Value and Exit Velocity for Flares

If a flare is also subject to both an ERCB and an ESRD approval, the more stringent requirement on minimum heating value will apply.

1) The combined net or lower heating value of gas, including make-up fuel gas, directed to a flare must not be less than 20 megajoules per cubic metre (MJ/m^3), except as noted below:

   a) If existing stacks have an established history of stable operation and compliance with the *AAAQO* (the licensee, operator, or approval holder is expected to support claims that existing stacks have operated satisfactorily over time), the licensee, operator, or approval holder is allowed to maintain the current heating value provided it is not less than 12 MJ/m^3.

      i) If flare stacks have a history of flame failure, odour complaints, or exceedances of the *AAAQO*, the licensee, operator, or approval holder must operate with a combined flare gas heating value of not less than 20 MJ/m^3.

   b) The combined net or lower heating value of acid gas plus make-up fuel gas directed to existing or new flares must not be less than 12 MJ/m^3 under any circumstance.

   c) Sour gas plant emergency systems must be configured to ensure that the flared gas heating value is not less than 12 MJ/m^3 and that the *AAAQO* are met.

      i) The ERCB recommends that 20 MJ/m^3 heating value be maintained for nonroutine flaring but recognizes that short-duration emergency flaring with a gas heating value of less than 20 MJ/m^3 may occasionally occur.

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2) If fuel make-up is required, it must be specified for flare stacks by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.[15]

   a) Equipment controls must be installed, and operating procedures must be documented to ensure minimum fuel gas make-up during routine and nonroutine operating conditions.

   b) Facilities must be operated in compliance with specified minimum fuel gas make-up requirements.

3) The flare tip diameter must be properly sized for the anticipated flaring rates. The *ERCBflare.xls* spreadsheet provides a range of recommended values.

   a) The ERCB recommends that stacks be designed to avoid downwash due to low exit velocities and excessive noise due to high exit velocities.

4) Equipment and controls design information must be provided to the ERCB upon request if the ERCB determines that there is a concern with the equipment or controls.

5) Operating limits and procedures must be provided to the ERCB immediately upon request.

7.1.2 Minimum Residence Time and Exit Temperature for Incinerators

If an incinerator is subject to an *EPEA* approval, any requirements regarding minimum residence time or exit temperature in that approval will take precedence over these requirements. The requirements below do not apply to sour gas plants subject to ESRD approvals.

1) Incinerators must provide a minimum residence time[16] of 0.5 seconds at maximum flow rate or more as required for complete combustion of heavier gases.

   a) Incinerators must be operated without exposed flame.

   b) If the gas contains less than 10 mol/kmol (1 per cent) H_2S and the unsupplemented heating value of the gas is 20 MJ/m^3 or more, no minimum residence time is required.

2) Incinerators must operate with a minimum exit temperature[17] of 600°C.

   a) For combustion of gases with less than 10 mol/kmol (1 per cent) H_2S and an unsupplemented heating value of 20 MJ/m^3 or more, no minimum exit temperature or temperature monitoring is required.

   b) For combustion of gases with more than 50 mol/kmol (5 per cent) H_2S, the facility must be designed to automatically shut down if the exit temperature of the incinerator drops below either 600°C or the required temperature to meet *AAAQO*, whichever is higher.

      i) The incinerator must also be equipped with process temperature control and recording.

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[15] *Engineering and Geoscience Professsions Act*, RSA 2000 c. E-11, as amended.

[16] Residence time is calculated between the top of the final burner and the stack exit.

[17] Exit temperature must be measured within one stack diameter of the exit. A shielded thermocouple must be used if the burner flame is visible to the temperature monitor. For further information, consult the Alberta Stack Sampling Code or contact Alberta Environment and Sustainable Resource Development.

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ii) All violations, together with measures taken to prevent recurrence, must be immediately reported by the licensee, operator, or approval holder to the appropriate ERCB field centre.

3) Any operator proposing to use an enclosed combustion technology that does not meet the above requirements (minimum exit temperature and minimum residence time) must submit third-party verified conversion efficiency test results to the ERCB Technical Operations Group for approval unless the facility is subject to an *EPEA* approval.

   a) Test programs and submissions must be provided by a qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*.[18] and must include

      i) inlet gas parameters, including flow rates and composition;

      ii) stack gas exit parameters, including temperature and composition;

      iii) material and energy balance calculations;

      iv) a mass-weighted conversion efficiency value representative of the exit conditions (see section 7.1.2[6] below);

      v) discussion of the variation of measured and calculated results, depending on sampling location across the stack; and

      vi) discussion of extending test results to other inlet conditions, including discussion of inlet limitations for H_2S concentration and inlet gas flow rate.

   b) All testing must meet the Alberta Stack Sampling Code.[19]

   c) Temperature monitoring and reporting requirements would still apply.

4) Equipment and controls design information must be provided to the ERCB upon request if the ERCB determines that there is a concern with the equipment or controls.

5) Operating limits and procedures must be provided to the ERCB immediately upon request.

6) Any licensee, operator, or approval holder using incinerators must be able to provide details about the conversion efficiency of the equipment. Any of the following are considered to be acceptable evidence of compliance with this requirement:

   a) the design at the maximum specified capacity meets the residence time, temperature, and conversion efficiency requirements (see [6][b] below), as calculated using the *ERCBincin.xls* spreadsheet

   b) the conversion efficiency for incinerators is 99 per cent or more, based on one of the following:

      i) the manufacturer's third-party-verified conversion efficiency test results, provided that the tests were conducted under conditions representative of the facility design

      ii) actual field measurements of conversion efficiency from the operating facilities following start-up (see also section 7[3]) .

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[18] *Engineering and Geoscience Professsions Act*, RSA 2000 c. E-11, as amended

[19] Copies of the Alberta Stack Sampling Code are available at cost from the Queen's Printer.

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c) If conversion efficiency is less than 99 per cent, the incinerator will be considered to operate as a flare and must meet all requirements for flares, including stack height.

7.2 Smoke Emissions

1) Smoke emissions from a well, battery, or gas plant must be controlled in accordance with sections 7.040(1) and 9.050(6)(d) of the *OGCR*, except under emergency circumstances that involve equipment failure or as otherwise approved by the ERCB Technical Operations Group.

   a) Routine gas combustion must not result in continuous or repeat black smoke emissions.

   b) Black smoke from nonroutine or emergency flaring must not exceed an average of 40 per cent opacity over six consecutive minutes or as defined, after the issue of this directive, in Alberta's *Environmental Protection and Enhancement Act Substance Release Regulation.*[20]

2) Any smoke emissions that may result in public concern must immediately be reported to the appropriate ERCB field centre.

7.3 Ignition

1) Acid gas and sour gas flares and incinerators must have reliable systems that ensure continuous ignition of any gas that may discharge to the device.

   a) At all facilities (excluding gas plants and batteries regulated as bitumen sites) where the gas contains more than 10 mol/kmol H_2S, a pilot or automatic ignition device must be installed on flares and incinerators for continuous (e.g., sour water or condensate tank flash-gas) and intermittent (e.g., emergency depressuring) sources.

   b) At batteries regulated as bitumen sites (see appendix 12) where the H_2S release rate is greater than 0.04 m^3/hr, a pilot or automatic ignition device must be installed on flares and incinerators for continuous (e.g., storage tank flash-gas) and intermittent (e.g., truck loading operations) sources.

   c) At gas plants where gas contains more than 10 ppm H_2S, pilots and automatic ignition must be installed on flares and incinerators.

   d) If repeat failures have occurred or off-lease odours or other impacts have resulted from failure to ensure ignition of sour gas, regardless of H_2S content, the ERCB may require installation of

      i) pilots and automatic ignition, and/or

      ii) flame failure detection and alarms.

2) Manual flare and incinerator ignition subject to good fire safety practices will be accepted for nonroutine purposes where

   a) no continuous gas flow exists, and

   b) no automatic relieving systems are connected to the stack.

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[20] Substance Release Regulation AR 124/93

7.3.1 Requests to Extinguish Flare Pilots at All Batteries

Significant volumes of fuel gas are used to sustain pilots for emergency flares at producing facilities. Continuous pilots may be necessary where gas is flared on a constant or routine basis (see section 7.3) or where sour gas can potentially be released from pressure safety valves (PSVs) or emergency shutdown valves (ESDVs). In situations where gas is not continuously or routinely flared, where ESDVs are not configured to depressure facilities to flare, and where maximum foreseeable operating pressures are well below PSV release pressures, the potential exists to safely conserve natural gas by extinguishing the flare pilots.

When considering a request to extinguish flare pilots, the ERCB field centre takes into account both local conditions and the operating history of the facility.

1) The licensee, operator, or approval holder must get approval from the appropriate ERCB field centre to extinguish flare pilots at sour gas batteries.

2) The issuing of an approval is only considered if

   a) the maximum design operating pressure of production piping and pressure vessel systems is greater than 105 per cent of the maximum stabilized static wellhead pressure of all wells connected to the battery;

   b) there will be no continuous or routinely flared gas streams;

   c) the facility is connected to sweet or level-1 or level-2 sour wells, as defined in *ID 97-06*;

   d) no active injection or cycling schemes are taking place in or planned for any pools with wells connected to the facility;

   e) the facility connections to the flare are isolated with rupture disks upstream of PSVs. This is subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* (AR 49/2006) administered by the Alberta Boilers Safety Association; and

   f) all manual depressuring valves connected to the flare system contain double block valves.

3) Requirements for extinguishing flare pilots are in appendix 11.

4) If the licensee, operator, or approval holder proposes to connect additional wells to an existing approval, they must first supply updated information and get approval from the appropriate ERCB field centre.

7.4 Stack Design

Flares and incinerators must meet or exceed the following stack design requirements:

1) Flare and incinerator stacks must be designed so that the radiant heat intensity at ground level will not exceed 4.73 kilowatts per square metre (kW/m^2).

   a) Ground-level radiant heat determinations for flares must be based on calculation procedures outlined in the *ERCBflare.xls* spreadsheet, *ANSI API Standard 521* section 6.4.2.3, or *GPSA Engineering Data Book* (13th edition), section 5. Incinerators must be operated without exposed flame.

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b) Exceptions to the requirement in section 7.4(1) will be considered on request to the ERCB Technical Operations Group, provided an equivalent level of safety can be ensured.

i) In such cases, the licensee, operator, or approval holder must restrict access to the area where the radiant heat intensity guideline could be exceeded and must ensure that this area is free of combustible materials and vegetation. Access restrictions must include appropriate warning signs, and the area must be clearly marked.

ii) Appropriate procedures (e.g., safe-work permit system) must be in place when it is necessary to work within the area where the radiant heat intensity guideline could be exceeded.

2) Flares and incinerators located within a distance of 5 times the height of any neighbouring buildings must have a height of at least 2.5 times the height of the highest building, tank, or enclosed structure on the lease site.

- The foregoing does not apply to devices for destruction of trace vent gases, such as those emitted from gas dehydrators.

3) Flare stacks for acid or sour gas containing more than 10 mol/kmol H_2S must have a height of at least 12 m above ground level. For batteries regulated as bitumen sites (see appendix 12) where the maximum potential H_2S release rate is greater than 0.04 m^3/hr, the minimum height above ground level for the flare stack or incinerator is 12 m, or such greater height as may be required to ensure that the *AAAQO* are not exceeded.

4) Flares and incinerators must be high enough to provide adequate plume dispersion to comply with the *AAAQO* for SO_2 (see section 7.12).

a) Proper stack heights must be used in order to minimize fuel consumption. If the use of supplemental fuel gas is proposed, all other options must be investigated first. Fuel gas use and amounts must be justified.

5) Interconnecting lines to the flare or incinerator must be secured to prevent whipping or flailing.

7.5 Nonroutine Sour and Acid Gas Flaring/Incineration Procedures

A licensee, operator, or approval holder must meet the requirements in this section or those in table 1, whichever is more stringent and results in more gas being shut in.

Devices for combustion of sour or acid gas must be designed and evaluated to ensure compliance with the *AAAQO* for SO_2. Evaluations must use methodologies acceptable to the ERCB Technical Operations Group and ESRD. One of the methods described in section 7.12 or ESRD's *Non-Routine Flaring Modelling Guidance* must be used.

1) A cumulative emissions assessment must be conducted if a flaring event is routine and if modelling results of the individual source exceed one-third of the *AAAQO* for SO_2 (see section 7.12).

2) It is not necessary to do a cumulative emissions assessment if the routine flaring is reasonably expected to be of short duration (less than four hours). Cumulative assessment requirements are intended to address the effects of multiple or continuous SO_2 sources in a given area (see section 7.12.3). Even if a cumulative emissions

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assessment is not required, modelling may still be required, as described in section 7.12.

a) Operating procedures must be put into place to limit the release duration if the routine stack design is based on the above exception.

3) If operating procedures and controls are used to limit the magnitude or the duration of the event, they must be documented and the facility must be operated in accordance with these procedures.

a) Automated shutdowns must be installed in facilities that are not staffed 24 hours/day (i.e., are semi-attended) to ensure compliance with this requirement.

b) Staff responsible for operations must be aware of the current operating procedures and must be trained at following them.

4) Operating procedures and related dispersion evaluations must be provided to the ERCB upon request.

7.6 Liquid Separation

Entrained liquids in a flare or incinerator stream may reduce combustion efficiency and contribute to increased emissions of total reduced sulphur compounds, hydrocarbons, and products of incomplete combustion. Proper gas-liquid separation facilities adequate to protect the pipeline system or gas combustion system must be used.

Note that for the purposes of this section and section 7.6.1, the terms knockout, knockout drum, scrubber, and separator are used interchangeably. The following requirements apply to all of these devices.

1) Liquid separation equipment must be provided in both temporary (including well test) and permanent flare and incinerator systems to prevent the carryover of liquid hydrocarbons, water, or other liquids.

2) Flare and incinerator separators must be designed in accordance with good engineering practice to remove droplets of 300 to 600 micron diameter and larger (see ANSI/*API Standard 521*).

a) Designs must be based on the lowest density hydrocarbon liquids that could be released to the flare or incinerator system.

3) The flare and incinerator separators or knockout drums must be designed to have sufficient holding capacity for liquid that may accumulate as a result of upstream operations, such as hydrocarbon carryover, liquid slugs, and line condensation.

4) All flare and incinerator separators and knockouts must have visual level indicators and operating procedures to ensure that the liquid retention in the vessel will not exceed the maximum design liquid level under all operating conditions.

a) For manually-operated flares and incinerators (e.g., maintenance flares) at well sites where the flare or incinerator is normally isolated from the process stream (i.e., manual block valve), visual level indicators are not required when the operator has operating procedures in place to ensure that no liquids are in the separator or knockout before the flaring event. After the flaring event, the operator must remove any liquids from the separator.

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i) These operating procedures must be provided to the ERCB immediately upon request.

5) All flare and incinerator separators and knockouts must have high-level facility shutdowns or high-level alarms that can be responded to by the operator before liquid carryover. If impacts such as liquid carryover or unacceptable smoke emissions (see section 7.2) have occurred as a result of failure to control liquid level, both high-level facility shutdowns and high-level alarms must be provided.

   a) Where only manually operated flaring or incineration will occur (such as manual equipment depressuring, handling hydrates, or for well cleanup and initial testing) and the operation is continuously attended, high-level facility shutdowns or high-level alarms are not required. Where personnel are not devoted to a flaring or incineration operation, the operation will not be considered to be continuously attended, despite a facility being continuously staffed.

6) High-level alarms and facility shutdowns must be installed on all flare and incinerator separators where liquid streams are directed to the separator for storage or where free liquids are contained in continuously combusted streams.

7) Flare and incinerator separators or knockout drums used for liquid storage must be designed and be in accordance with ERCB *Directive 055: Storage Requirements for the Upstream Petroleum Industry*.

8) Design information on flare and incinerator system liquid separation equipment must be submitted upon request to the ERCB, including *Directive 056* facilities application review processes.

7.6.1 Exceptions to Separator Requirements

1) The ERCB does not require independent flare or incinerator separators in situations where the only vessels connected to the flare or incinerator are production separators equipped with an High Level Shut Down (HLSD) or equivalent devices or with a system that prevents liquids from entering the flare or incinerator. The following limitations apply to this exception:

   a) The HLSD must be configured to shut down and block in, but not depressure, the battery. The HLSD trip level must be set so that adequate vapour-liquid separation is not impaired at maximum liquid level and vapour flow rates.

   b) If liquid carryover involving spills occurs around the flare or incinerator or if black smoke is formed, the licensee, operator, or approval holder must install adequately sized flare or incinerator separators.

2) The ERCB does not require independent flare or incinerator separators for combustion devices that destroy trace vent gases emitted from gas dehydrators.

7.7 Backflash Control

Inadequately purged flare or incinerator systems may have enough oxygen present to support combustion. Backflash may occur when the linear velocity of the combustible mixture of gas and air in the system is lower than the flame velocity.

1) The licensee, operator, or approval holder must take precautions to prevent backflash using appropriate engineering and operating practices, including

   a) installiong flame arresters between the point of combustion and the flare or incinerator separator, or

   b) providing sufficient flare header sweep gas velocities (i.e., purge or blanket gas) to prevent oxygen intrusion into the flare or incinerator system.

2) Check valves are not an acceptable form of backflash control.

3) Safe work procedures must be in place to ensure complete purging of oxygen from flare or incinerator systems before ignition.

4) The licensee, operator, or approval holder must provide information on backflash controls to the ERCB upon request if the ERCB determines that there is a concern with the equipment or controls.

7.8 Flare and Incinerator Spacing Requirements

Licensees, operators, and approval holders must follow good engineering and safety practices in the layout of facilities. Despite liquid separation requirements, unexpected liquid carryover to flares and incinerators can happen. Adequate spacing of these devices from areas frequented by workers and from sources of combustible gas is prudent. A licensee, operator, or approval holder must consult fire protection codes and guidelines as part of facility design.

1) Flares and incinerators must be located, as measured from the base of the stack, at least

   a) 50 m from wells, not including water disposal wells or water injection wells where there is no risk of flammable vapours;

   b) 50 m from storage tanks containing flammable liquids or flammable vapours;

   c) 25 m from any oil and gas processing equipment. This does not apply to combustion devices that destroy trace vent gases, such as those emitted from gas dehydrators. These devices must be designed to prevent ignition of gas that may leak from surrounding equipment (i.e., devices must be equipped with flame arresters); and

   d) 25 m from heavy oil/bitumen wells, storage tanks, or other sources of ignitable vapour, including lined-earth excavations used to store waste oil at batteries regulated as bitumen sites (see appendix 12).

Flare knockout drums and integral knockout drums are exempt from flare and incinerator spacing requirements provided they have no means to vent to the atmosphere.

The incinerator that combusts gas from the sulphur recovery process is not required to meet incinerator spacing requirements for sulphur plant process equipment (i.e., converters and condensers).

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2) Flares and incinerators must be located, designed, and operated so that they are not a hazard to public property. They must be at least

   a) 100 m away from surface developments as defined in *Directive 056* (except for surveyed roadways or road allowances, which must be 40 m from flares and incinerators),[21] and

3) The licensee, operator, or approval holder must ensure that areas around flares and incinerators are not subject to fire hazards. Flare or incinerator spacing and operating practices must comply with the *Forest and Prairie Protection Act*[22] and any regulations under that act.[23]

4) The ERCB recommends that the licensee, operator, or approval holder also comply with the *Forest and Prairie Protection Regulations*, part I (*AR 135/72*) in unforested areas where there is a fire hazard associated with flare and incinerator operations.

5) In certain circumstances, the ERCB Technical Operations Group may consider variances to ERCB flare and incinerator spacing requirements.

   a) The ERCB discourages variance requests for new facilities.

   b) Existing well site equipment spacing waivers in effect before the effective date of this directive are maintained.

   c) A licensee, operator, or approval holder requesting a spacing variance must first consult relevant codes and engineering practices and provide related information in support of the variance request.

7.9 Compliance with Fire Bans

Information on fire bans issued by Alberta Sustainable Resource Development can be found at www.albertafirebans.ca, directly from local municipal districts, or by calling 1-866-310-FIRE (3473).

7.10 Noise

1) Flares and incinerators must be designed to operate in compliance with *Directive 038*.

7.11 Flare Pits

The ERCB recommends that the licensee, operator, or approval holder phase out flare pits used for routine gas flaring.

Flare pits must not be used at any facilities built after July 1, 1996. For facilities built before July 1996, flaring in pits is allowed, provided the following requirements are met:

1) All existing flare pits must be decommissioned by December 31, 2014.

2) Produced liquids must not enter the pit, in accordance with section 8.080 of the *OGCR*.

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[21] The 40 m spacing requirement applies to public road allowances and roads to which the public has open access. There is no spacing requirement for private licensee access roadways or private roadways on operating sites.

[22] *Forest and Prairie Protection Act*, RSA 2000, c. F-19, as amended

[23] As at the date of this directive *The Forest and Prairie Protection Regulations*, AR 135/72

3) Flaring of sour gas must comply with the *AAAQO*.

4) Gas containing more than 10 mol/kmol H_2S must not be flared in pits.

5) The licensee, operator, or approval holder must conduct evaluations of solution gas flares for flare pits as described in sections 2.3 and 2.9 and implement the resulting decision.

6) Access restrictions and procedures must be in place in areas around flare pits where ground-level radiant heat intensity at maximum flare rates will exceed 4.73 kW/m^2.

7) If the facility is modified or if the facility increases its average annual production, the flare pit must be replaced with a flare stack.

8) The ERCB can require the licensee, operator, or approval holder to replace flare pits with flares systems if any part of the facility is in noncompliance.

9) Operation of flare pits must comply with the provisions of the *Forest and Prairie Protection Act*[24] and with any regulations under that act.[25]

7.12 Dispersion Modelling Requirements for Sour and Acid Gas Combustion

The following requirements apply to the combustion of sour gas in process equipment, such as steam generators and process heaters, as well as to flares and incinerators.

1) The licensee, operator, or approval holder must demonstrate, using dispersion modelling methods outlined in ESRD's *Air Quality Model Guideline*, that SO_2 and H_2S emissions from the burning of sour and acid gas will not result in exceedance of *AAAQO* if the gas contains the following amounts or more:

   - 10 mol/kmol H_2S,
   - one tonne per day of sulphur instantaneous emission rate, or
   - the maximum potential H_2S release rate is greater than 0.04 m^3/hr for batteries regulated as bitumen sites (see appendix 12).

   A licensee, operator, or approval holder combusting gas below these concentrations and emission rates is encouraged to consider dispersion modelling as part of environmental considerations. Facilities requiring approval from ESRD under the *EPEA* may need more detailed evaluation. A licensee, operator, or approval holder should consult ESRD directly in these instances.

2) Dispersion modelling must be done by qualified technical personnel using computer models and methodologies acceptable to ESRD or, if appropriate, the method described in sections 7.12.4 and 7.12.5 and appendix 7.

[24] *Forest and Prairie Protection Act*, RSA 2000, c. F-19, as amended
[25] As at the date of this directive, *The Forest and Prairie Protection Regulations*, AR 135/72

7.12.1 Modelling Approach

The definitions of screening and refined dispersion modelling assessments are in Appendix 8.

1) The licensee, operator, or approval holder must
   - select an appropriate model,
   - be able to demonstrate that the model selected is appropriate and follows ESRD accepted methodologies and standards, and
   - use representative input parameters (e.g., flow rate, gas composition) within the model and be prepared to demonstrate that those parameters are representative.

7.12.2 Individual Source

1) Initial modelling may be conducted using the screening assessment provided in the *ERCBflare.xls* and *ERCBincin.xls* spreadsheets.

2) For a screening assessment, ambient air quality modelling must use
   a) stack-specific terrain extracted from 1:50 000 topographical NTS maps,
   b) the point source (not flare) option,
   c) full screening meteorology,
   d) appropriate land use characteristics, and
   e) emission parameters as calculated by the *ERCBflare.xls* and *ERCBincin.xls* spreadsheets (e.g., velocity, diameter, and temperature inputs for dispersion modelling).

3) Modelling must address a full range of expected flow rate conditions and may include the low, average, and maximum flow rate.

4) Complex terrain modelling must be used unless terrain elevations are less than the complex terrain criteria, in which case parallel airflow modelling can be applied.

5) The selected flare or incinerator design must not result in ground-level SO_2 concentrations higher than those in the *AAAQO*.
   a) A refined assessment may be used if the screening assessment results in an impractical stack height.
   b) If it is not practical to design flares or incinerators of sufficient height for adequate dispersion, the licensee, operator, or approval holder may consider
      i) using an air quality management plan (see appendix 7),
      ii) operating procedures and process controls to prevent emission rates or durations that would exceed the *AAAQO* (see sections 7.5, 7.12.4), and
      iii) adding fuel gas to increase heat release and plume rise. As stated in section 7.4, proper flare stack height must be used to minimize fuel consumption.
   c) The risk-based criteria discussed in section 7.12.4 do not apply to continuous (nontemporary) sour gas combustion at permanent facilities.

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7.12.3 SO_2 Cumulative Emissions Assessment

If predicted maximum hourly average ground-level concentrations for the individual continuous source are more than one-third of the *AAAQO* for SO_2, then the licensee, operator, or approval holder must conduct an assessment of cumulative effects of all routine SO_2 sources.

1) The following steps must be followed for cumulative emissions assessments:

   a) Identify the farthest downwind location where predictions exceed one-third of the hourly average *AAAQO* for SO_2 to define the radius of influence.

   b) Identify all other continuous sources of SO_2 within this radius of influence up to a maximum of 20 km; if no other sources of SO_2 are within the radius, no further modelling is required.

   c) Quantify SO_2 emissions from these other sources and obtain all necessary input data, such as stack height and other parameters (the licensee, operator, and approval holder must share related data with each other on a timely basis). Maximum hourly flow rate conditions must be used for all sources in the radius of influence.

      i) In applications for a continuous source, other sources must be modelled at licensed emission rates.

      ii) SO_2 cumulative assessments are not required for nonroutine flaring, venting, and incineration (e.g., well test or planned maintenance blowdown),.

   d) Model the cumulative effects of the SO_2 emission sources.

   e) If the sum exceeds the *AAAQO*, determine the appropriate stack height required to meet the *AAAQO*. All refined modelling must follow the methods outlined in the *Air Quality Model Guideline* (2013).

7.12.4 Temporary and Well Test Flaring Dispersion Modelling

This section applies to temporary events that may require a permit (as described in section 3) and well test flaring or incineration activities. These activities include well testing, well cleanup, well servicing, coalbed methane well testing, underbalanced drilling, and sour gas pipeline (as defined in *Directive 56*) blowdown through temporary flare or incinerator equipment. These activities exclude nonroutine flaring or incineration at permanent ERCB-licensed facilities.

1) The licensee, operator, or approval holder must complete either the flaring (*ERCBflare.xls*) or incinerator (*ERCBincin.xls*) spreadsheet.

2) Information on ambient air quality impact evaluations must be included in requests to burn sour gas or, if no permit is required, must be provided to the ERCB upon request. The dispersion modelling within *ERCBflare.xls* or *ERCBincin.xls* may be sufficient if a screening assessment is adequate.

3) Sour gas flares and incinerators must be designed for the gas composition and flow rates of the situation for which there is a temporary permit (see section 7 for further information).

4) Equipment design or the operating procedures, or both, must address all modelled predictions that exceed the *Alberta Ambient Air Quality Objectives*, excluding predicted values that meet the risk-based criteria. The risk-based criteria only apply to temporary events.

   a) Risk-based criteria for temporary events allow limited exclusion of predicted ambient air quality results, provided that

      i) the 99th percentile predicted values at a receptor do not exceed the one-hour SO_2 *Alberta Ambient Air Quality Objective*, and

      ii) the 99.9th percentile predicted values do not exceed a predicted one-hour SO_2 ambient concentration of 900 micrograms (µg) per m^3.

      Note that whereas model predictions up to 900 $\mu g/m^3$ will be considered, actual exceedances of the *Alberta Ambient Air Quality Objectives* are never permitted.

   b) Risk-based criteria for parallel airflow are incorporated into the flaring (*ERCBflare.xls*) spreadsheet. For incinerators, refined modelling may be required to demonstrate that the risk-based criteria are met for parallel airflow.

   c) Risk-based criteria may be used when refined and complex terrain modelling is conducted for temporary events.

   d) The ERCB Technical Operations Group will also consider operator use of the risk-based criteria in situations where air quality management plans (see appendix 7) are necessary to ensure compliance with the *Alberta Ambient Air Quality Objectives*.

      i) Air quality management plan decision criteria may be based on meteorological or ambient air quality monitoring data.

5) Concurrent temporary sour gas burning (i.e., multiple well test flaring/incinerating) must not occur within 14 km of each other unless a licensee can demonstrate that the cumulative emissions from flaring can meet *AAAQO*.

6) Licensees must retain, for one year after the flaring/incineration event, information on dispersion assessments for flares or incinerators that require dispersion modelling but do not require a flaring permit (see section 3.3.2). This information must be provided to the ERCG Technical Operations Group upon request.

7.12.5 Nonroutine Flaring Dispersion Modelling

This section applies to nonroutine planned and unplanned flaring from permanent flares. Temporary and well testing activities described in section 7.12.4 are not included here.

"Nonroutine" applies to intermittent and infrequent flaring, venting, and incineration. There are two types of nonroutine flaring: planned flaring and unplanned flaring.

- Planned flaring—Flare events where the operator has control over when flaring will occur, how long it will occur and the flow rates. Planned flaring results from the intentional depressurization of processing equipment or piping systems. Examples of planned flaring include: pipeline blowdowns, equipment depressurization, start-ups,

facility turnarounds, and well tests. Note that well testing dispersion modelling criteria are addressed in section 7.12.4.

- Unplanned flaring—Emergency or upset operational activities closely associated with facility health and safety. Flare events where the operator has no control of when flaring will occur. There are two types of unplanned flaring upset flaring and emergency flaring.

  - Upset flaring occurs when one or more process parameters fall outside the allowable operating or design limits and flaring is required to aid in bringing the production back under control. Examples of upset flaring include: off-spec product, hydrates, loss of electrical power, process upset, and operation error.
  - Emergency flaring occurs when safety controls within the facility are enacted to depressurize equipment to avoid possible injury or property loss resulting from explosion, fire, or catastrophic equipment failure. Examples of upset flaring include: PSV overpressure and emergency shutdown.

Figure 8 summarizes the process for managing the nonroutine flaring of sour gas.

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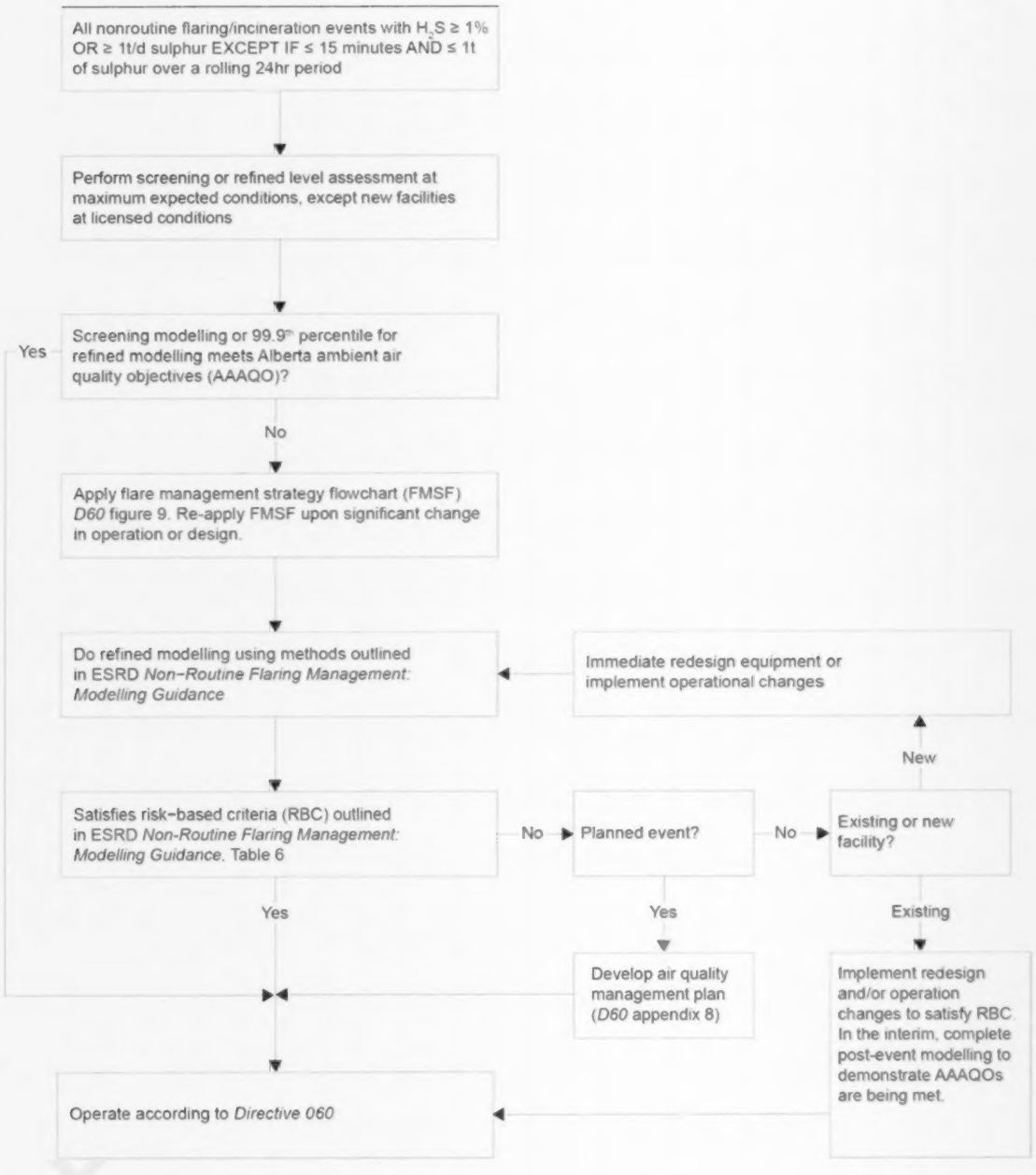
All nonroutine flaring/incineration events with $H_2S \geq 1\%$ OR ≥ 1t/d sulphur EXCEPT IF ≤ 15 minutes AND ≤ 1t of sulphur over a rolling 24hr period
Perform screening or refined level assessment at maximum expected conditions, except new facilities at licensed conditions
Screening modelling or 99.9th percentile for refined modelling meets Alberta ambient air quality objectives (AAAQO)?
Yes
No
Apply flare management strategy flowchart (FMSF) *D60* figure 9. Re-apply FMSF upon significant change in operation or design.
Do refined modelling using methods outlined in ESRD *Non-Routine Flaring Management: Modelling Guidance*
Immediate redesign equipment or implement operational changes
New
Satisfies risk-based criteria (RBC) outlined in ESRD *Non-Routine Flaring Management: Modelling Guidance*, Table 6
No
Planned event?
No
Existing or new facility?
Yes
Yes
Existing
Develop air quality management plan (*D60* appendix 8)
Implement redesign and/or operation changes to satisfy RBC. In the interim, complete post-event modelling to demonstrate AAAQOs are being met.
Operate according to *Directive 060*

Figure 8. Comprehensive management of the nonroutine flaring of sour gas

1) The licensee, operator, or approval holder must evaluate impacts of nonroutine sour gas flaring on ambient air quality if

   a) it is proposed to burn sour gas containing 10 mol/kmol H_2S (1 per cent H_2S) or more,

   b) the maximum potential H_2S release rate is greater than 0.04 m^3/hr for batteries regulated as bitumen sites (see appendix 12), or

   c) 1 tonne of sulphur mass release during the event or the day (for multiple releases).

   Single nonroutine flare events that are predicted to be less than or equal to 15 minutes in duration and predicted to emit less than 1 tonne of sulphur over a rolling 24-hour period are exempt from modelling requirements.

2) For new permanent flare stacks the licensee, operator, or approval holder must meet nonroutine flaring dispersion modelling criteria effective immediately upon the sanctioning of this framework.

3) For existing permanent flare stacks the licensee, operator, or approval holder must assess nonroutine flaring dispersion modelling criteria within the following timelines:

   a) Sour gas processing plants as defined in the *Environmental Protection and Enhancement Act - Activities Designation Regulation*: within one year of the sanctioning of this framework.

   b) Compressor stations, dehydration sites, gas and oil batteries: within two years of the sanctioning of this framework.

   c) Well sites: within four years of the sanctioning of this framework.

4) Initial screen modelling may be conducted using ERCBflare or dispersion modelling methods outlined in ESRD's *Air Quality Model Guideline*. If nonroutine refined modelling is required or if stack design is impractical, the licensee must apply the flare management strategy flow chart (figure 9) or equivalent, and dispersion modelling evaluations must be conducted using methodologies described in ESRD's *Non-Routine Flaring Modelling Guidance*. The flare management strategy flow chart and refined modelling must be reapplied if facility operation or design changes significantly.

5) If modelling of worst-case unplanned flaring scenarios show 99.9th percentile hourly predicted concentrations in excess of the ERCB SO_2 evacuation criteria from D071, the licensee, operator, or approval holder must implement design or operational changes such that risk-based criteria are met within three years of the assessment. In the interim, for each unplanned flaring event at the facility, the licensee, operator, or approval holder must do post-event dispersion modelling (See section 7.12.5[10]).

6) If modelling of worst-case scenarios shows that 99.9th percentile hourly predicted concentrations are lower than the ERCB SO_2 evacuation criteria from *Directive 071* and higher than the *Alberta Ambient Air Quality Objectives* for SO_2, then for each unplanned flaring event at the facility, the licensee, operator, or approval holder must do post-event dispersion modelling (See section 7.12.5[10]).

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7) For planned flaring events, the licensee, operator, or approval holder must develop flare management plans that meet the risk-based criteria to ensure that *AAAQOs* are not exceeded, and implement them during flaring. It is acceptable for modelling to be based on actual flows and gas compositions, not licensed values.

8) If refined modelling for nonroutine flaring is required, the licensee must not exceed the risk-based criteria maximum number of flaring hours per calendar year described in ESRD's *Non-Routine Flaring Modelling Guidance* table 1. The licensee, operator, or approval holder must log all flaring events, including flare duration, volume, and rates.

9) If nonroutine flaring exceeds the risk-based criteria maximum number of flaring hours per year described in ESRD's *Non-Routine Flaring Modelling Guidance* table 1 or if the event results in an exceedance of the *Alberta Ambient Air Quality Objectives* for SO_2, the licensee, operator, or approval holder must conduct post-event dispersion modelling (see section 7.12.5[10]) and contact the ERCB Technical Operations Group immediately.

10) If post-modelling is required, the actual conditions must be used. If site-specific meteorological data during the event is not available, five years of meteorological data from a standard period is recommended using the ESRD data set (http://www.albertamm5data.com/). One month per year must be modelled from the data set, centred around the month of the event.

11) If the ERCB Technical Operations Group determines that the dispersion modelling has not been completed in accordance with *Directive 060* requirements, the licensee, operator, or approval holder will be subject to enforcement action.

12) The licensee, operator, or approval holder is not required to provide copies of nonroutine dispersion modelling or a flare management strategy flowchart to the ERCB unless requested. Upon request, the licensee, operator, or approval holder must provide the evaluation to the ERCB within five working days.

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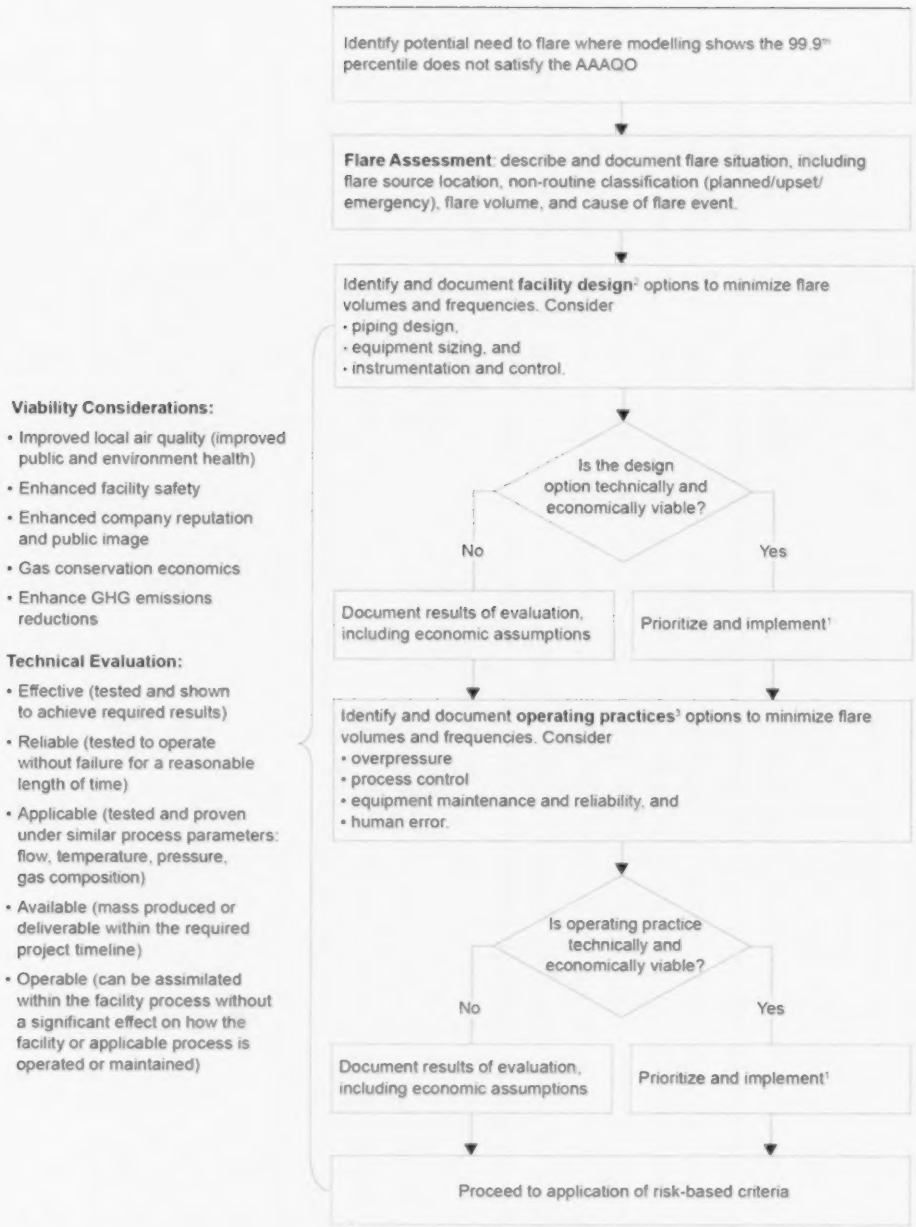
Identify potential need to flare where modelling shows the 99.9th percentile does not satisfy the AAAQO
Flare Assessment: describe and document flare situation, including flare source location, non-routine classification (planned/upset/emergency), flare volume, and cause of flare event.
Identify and document facility design[2] options to minimize flare volumes and frequencies. Consider
• piping design,
• equipment sizing, and
• instrumentation and control.
Viability Considerations:
• Improved local air quality (improved public and environment health)
• Enhanced facility safety
• Enhanced company reputation and public image
• Gas conservation economics
• Enhance GHG emissions reductions
Is the design option technically and economically viable?
No
Yes
Document results of evaluation, including economic assumptions
Prioritize and implement[1]
Technical Evaluation:
• Effective (tested and shown to achieve required results)
• Reliable (tested to operate without failure for a reasonable length of time)
• Applicable (tested and proven under similar process parameters: flow, temperature, pressure, gas composition)
• Available (mass produced or deliverable within the required project timeline)
• Operable (can be assimilated within the facility process without a significant effect on how the facility or applicable process is operated or maintained)
Identify and document operating practices[3] options to minimize flare volumes and frequencies. Consider
• overpressure
• process control
• equipment maintenance and reliability, and
• human error.
Is operating practice technically and economically viable?
No
Yes
Document results of evaluation, including economic assumptions
Prioritize and implement[1]
Proceed to application of risk-based criteria

Notes

[1] After prioritization, schedule for implementation in a staged process to ensure operational changes are implemented first, highest priority projects are implemented first, minimum disruption to current operations, adequate capital is available for implementation, and regulatory targets or objectives are achieved.

[2] Section 5.2 of the CAPP *Best Management Practices for Facility Flare Reduction* provides a description of facility design considerations.

[3] Section 6.2 of the CAPP *Best Management Practices for Facility Flare Reduction* provides a description of operational practice considerations.

Figure 9. Flare management strategy flowchart

8 Venting and Fugitive Emissions Management Requirements

Venting is not an acceptable alternative to conservation or flaring.

8.1 General Requirements

1) All continuous and temporary venting must be evaluated using the decision tree in the appropriate sections of this directive.

2) The licensee, operator, or approval holder must burn all nonconserved volumes of gas if volumes and flow rates are sufficient to support stable combustion.

   a) The ERCB may investigate vented volumes of 500 m^3/day, or even lower, if it appears that stable combustion of the gas may be feasible. Upon request, the licensee, operator, or approval holder must provide its justification for volumes not combusted. Vented volumes include tank venting and surface casing vents but do not include venting from pneumatic instruments.

   b) Where metering is not required for gas vented in association with heavy crude or crude bitumen production, the ERCB may at any time request a new GOR or hourly rate test to be performed to verify vented volumes. Refer to *Directive 017: Measurement Requirements for Oil and Gas Operations* section 4.3.5.3 for acceptable testing methods. Upon request, the operator must provide the evaluation to the ERCB within 30 working days.

3) Provided that all other requirements in section 8 of this directive are met, section 8.031 of the *OGCR* permits the connection of pressure-relieving devices at oil production batteries to open tanks (i.e., "pop tanks").

4) Hydrocarbon products stored in atmospheric storage tanks at gas plants, compression stations, and gas batteries must not have a true vapour pressure of more than 83 kilopascals (kPa) at 21.1°C if the tanks are vented to the atmosphere.

5) Temporary, short-term venting is allowed at wells (e.g., for well unloading and liquid cleanup), facilities, batteries where conservation is in place (see partial equipment outages in table 2), and pipelines (for natural gas transmission systems, see section 6.3), with the following conditions:

   a) Gas must be sweet.

   b) Gas must not contain any free hydrocarbon liquid (if free hydrocarbon liquids are present in the produced gas, a flare [or other gas combustion device] and liquid separation must be used).

   c) All liquids must be separated and contained in accordance with the storage requirements of *Directive 055*.

   d) Total gas volume must not exceed 2 10^3 m^3, and the duration must not exceed 24 hours. (This does not include the cleanout phase for well testing and servicing, when liquids and noncombustible gases may prevent stable combustion. See section 8.5.)

   e) The licensee, operator, or approval holder must conduct notification in accordance with section 3.8 and table 2.

   f) The ERCB field centre may consider alternatives to these requirements should special circumstances warrant. The licensee, operator, or approval holder must

contact the appropriate ERCB field centre for approval of alternatives. For pipeline venting exemptions to these requirements, see section 6.2.

6) Temporary venting is not permitted within 500 m of a residence unless the residents consent and the venting is approved by the appropriate ERCB field centre.

7) Vented gas must not constitute an unacceptable fire or explosion hazard and must comply with the spacing requirements in section 7.8. Venting must also not occur closer than

   a) 25 m from any flame-type equipment (for diesel engines equipped with air intake shutoff device, see ERCB *Directive 036: Drilling Blowout Prevention Requirements and Procedures*);

   b) 50 m from a wellhead for vent stacks other than surface casing vents,

   c) 35 m from a wellhead for well testing and servicing of wells listed in section 1.1 of *Directive 008: Surface Casing Depth Requirements*. (Venting in association with water production from these wells [e.g., blowdowns, no service or well-test equipment] are exempt from the 35 m spacing), or

   d) 25 m from a wellhead for heavy oil/bitumen well, storage tank, or other ignitable vapour including lined earth excavations utilized for waste oil storage at batteries regulated as bitumen sites (see appendix 12).

8) An appropriate flame arrester or equivalent safety device, or proper engineering and operating procedures (e.g., sufficient sweep gas velocity) must be used on all vent lines connecting oil storage tanks to flare or incinerator stacks.

8.2 Limitations of Venting Gas Containing H_2S or Other Odorous Compounds

1) Gas containing more than 10 mol/kmol H_2S must not be vented to the atmosphere (excluding batteries regulated as bitumen sites). This includes gas off stock tanks, PSVs, and equipment blowdown systems.

   a) Sour pressure-relief valves must be tied into flare systems if the gas contains more than 10 mol/kmol H_2S or could result in off-lease H_2S odours.

2) H_2S must not be vented to the atmosphere at a release rate greater than 0.04 m^3/hr for batteries regulated as bitumen sites (see appendix 12),

   a) Sour pressure-relief valves must be tied into flare systems if the total H_2S release rate is greater than 0.04 m^3/hr H_2S or could result in off-lease H_2S odours.

3) Venting and/or fugitive emissions must not result in any H_2S odours outside the lease boundary. Venting and/or fugitive emissions must not result in any hydrocarbon odours outside the lease boundary that, in the opinion of the ERCB, are unreasonable either because of their frequency, their proximity to surface improvements and surface development (as defined in *Directive 056*), their duration, or the strength of their odour.

   a) The ERCB recommends that PSVs and blowdown systems be connected to a flare system where such systems are installed.

4) Venting must not result in exceedances of the *AAAQO* outside the lease boundary.

8.3 Limitations on Venting Gas Containing Benzene

1) The licensee or approval holder must control benzene emissions such that cumulative emissions from all sources (dehydrators plus other sources) at the facility or lease site do not exceed the limits in table 4 below.

Table 4. Cumulative facility or lease site benzene emission limits

Date facility or lease site commissioned	Benzene emission limits
Before January 1, 1999:	
• more than 750 m to permanent resident or public facility	5 tonnes/yr
• less than 750 m to permanent resident or public facility	3 tonnes/yr
January 1, 1999, to January 1, 2007	3 tonnes/yr
After January 1, 2007	1 tonne/yr

2) The licensee or approval holder must ensure that vented gas from dehydrators meets all requirements specified in *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators*.

8.4 Venting of Noncombustible Gas Mixtures

Release of inert gases such as nitrogen and carbon dioxide from upstream petroleum industry equipment or produced from wells may not have sufficient heating value to support combustion. These gases may be vented to atmosphere subject to the following requirement:

1) Noncombustible gas mixtures containing odorous compounds including H_2S must not be vented to the atmosphere if off-lease odours may result. Alternatives to venting such gas include flaring or incinerating with sufficient fuel gas to ensure destruction of odourous compounds.

8.5 Coalbed Methane Venting

A licensee, operator, or approval holder may vent gas as part of the evaluation of coalbed methane development and technologies if the requirements for venting are met (i.e., gas conservation has been determined not to be economically feasible, the ERCB has not directed that conservation be implemented, and flows will not support stable combustion). Once conservation or combustion of the gas is possible, these options must be used. If conservation is directed by the ERCB, the gas must be conserved.

Gas conservation in long-term coalbed methane projects must be evaluated, and test durations are limited by requirements found in section 3.2.

8.6 Fugitive Emissions Management

1) The facility licensee must develop and implement a program to detect and repair leaks.
   a) These programs must meet or exceed the Canadian Association of Petroleum Producers (CAPP) *Best Management Practice for Fugitive Emissions Management*.

2) The licensee, operator, or approval holder must use pressurized tank trucks or trucks with suitable and functional emission controls when transporting sour fluids from upstream petroleum industry facilities.

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9 Sulphur Recovery Requirements and Sour Gas Combustion

Certain types of oil production, gas gathering, and nonassociated gas battery facilities can have significant sulphur emissions from combustion (by flaring, incinerating, or use as equipment fuel) of sour solution gas, from low-pressure produced water flash-gas, and from flaring of glycol dehydrator vent gas. Appropriate pollution prevention measures must be implemented in such situations to minimize sulphur emissions from combustion of sour or acid gas.

1) Guidelines in *ID 2001-03* apply to sour gas plants and other upstream petroleum facilities such as oil production batteries, gas batteries, and pipeline facilities.

2) For in situ bitumen sites, the sulphur recovery requirements in table 1 of *ID 2001-03* apply. The sulphur inlet used to determine the sulphur recovery requirement in table 1 is based on total sulphur emissions from combustion of sour produced gas as fuel or by flaring or incineration divided by the number of days over a calendar quarter year.

9.1 Sulphur Recovery Exemption at Solution Gas Conservation Facilities

The ERCB and ESRD may deviate from sulphur recovery requirements in circumstances where sulphur emissions would be minimal and sulphur recovery would render gas conservation uneconomic.

Solution gas conservation clustering schemes that have a total inlet sulphur of between 1 and 5 tonnes/day may be considered for flexibility by ESRD and the ERCB in the application of *ID 2001-03*. Provisions for deviations from the sulphur recovery guidelines are in section 4 of *ID 2001-03*.

1) The licensee or operator must apply to the ERCB for a variance from the sulphur recovery guidelines as part of related production project applications submitted to the ERCB. The application must take the form of a nonroutine *Directive 056* application, and applicants must indicate on the application that the facility will **NOT** comply with the requirements of *Directive 060*.

2) The licensee or operator must demonstrate to the ERCB, using the methodology in section 2.9, that implementing sulphur recovery would make the gas plant uneconomic.

   a) If gas production with sulphur recovery is economic, the licensee or operator must implement sulphur recovery.

3) The licensee or operator must demonstrate that revenues and cost estimates are reasonable.

   a) Capital cost estimates for sulphur recovery must be based on appropriate technologies. The licensee or operator must identify cost-effective processes suited to the facilities in question.

   b) Information on the following must be available to the ERCB upon request:

      i) volumes of gas available, including assessment of clustering other gas sources in the area

      ii) incremental energy (e.g., fuel gas) requirements for gas compression and processing related to gas sweetening

      iii) incremental energy (fuel gas) requirements for sulphur recovery processes

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iv) H_2S concentration of gas, along with expected average sulphur emissions and variability of sulphur emissions

v) information on technology selection and costs for equipment (e.g., compression), gas gathering systems, and sulphur recovery processes. Note that the economic evaluation is based on incremental costs of gas conservation; therefore, equipment costs related to oil production, processing, and transportation must not be included

4) The licensee or operator must consult with residents within the radius set out in *Directive 056*, specifically explaining that a variance of the sulphur recovery guidelines is being applied for. Any objections must be disclosed in related facility applications.

5) The ERCB and ESRD will consider the scope of the production project, the duration of the sulphur emissions, and the views of the local public in making decisions on applying the sulphur recovery guidelines.

   a) The existing processes used for *EPEA* approvals for sour gas processing plants and for ERCB approvals will be used to measure public acceptance of any proposals. If there are no unacceptable impacts and nearby residents do not object, meeting the sulphur recovery guidelines may not be required for solution gas facilities.

   b) The ERCB does not allow multiple nonsulphur-recovery sour operating sites in close proximity where it is practical to consolidate the facilities in one location and install sulphur recovery.

      i) Sour gas facility proliferation guidelines in *ID 2001-03* section 6 stipulate how the ERCB will assess this matter.

6) The variances do not apply to sour gas production and processing facilities handling primarily nonassociated gas.

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10 Measurement and Reporting

The following requirements for measuring and reporting volumes of gas flared, incinerated, and vented are in addition to ERCB measurement requirements provided in *Directive 017: Measurement Requirements for Oil and Gas Operations*, *Directive 007*, and the *OGCR*.

1) The licensee, operator, or approval holder of oil, bitumen, and natural gas production and processing facilities (including well tests) must report, on the ERCB S-30 report and on PETRINEX, gas volumes of 0.1 10^3 m^3/month (adjusted to 101.325 kPa(a) and 15°C) or more that is flared, incinerated, or vented. This includes reporting all flaring, incineration, and venting from routine operations, emergency conditions, and the depressurizing of pipeline, compression, and processing systems. However, "incinerated" volumes must be reported as "flared," because the registry does not allow for reporting of "incinerated" volumes.

2) The licensee, operator, or approval holder must be able to demonstrate that volumes of gas are accurately and consistently determined (see sections 10.1 and 10.2).

3) If production submissions are not routinely submitted for a facility, as is sometimes the case for well completions, and if total volumes are not significant (less than 0.5 10^3 m^3 in total), the ERCB Technical Operations Group may waive the reporting requirement. Otherwise, the licensee, operator, or approval holder is to obtain a facility code and report the flared, incinerated, or vented gas volumes.

4) The ERCB recommends that the licensee, operator, or approval holder meter total flare streams in larger oil and gas batteries, pipeline facilities, and gas processing plants where there could be multiple connections to the flare system from sources such as process equipment, storage tank vents, pressure-relieving valves, manual blowdowns, and emergency vent valves, even when the volume is less than 0.5 10^3 m^3/d as a yearly average.

5) The licensee, operator, or approval holder must be able to provide the volume of fuel gas used for flare pilots and flare header purge gas to the ERCB upon request (see section 5.5[6]).

   a) Fuel gas used in flare systems (including fuel gas make-up to acid gas flares) is to be reported as part of the total fuel gas volume on PETRINEX.

   b) Fuel gas added to flare systems must be subtracted from the measured flare volumes if total flare gas measurement is used downstream of the fuel gas entry point.

6) For a gas well tied into an oil battery, the licensee, operator, or approval holder must report this gas on a separate production statement (for a gas battery) showing the gas delivery to the oil battery. A similar requirement is in place for oil well gas delivered to a gas battery. See *Directive 017*, section 4.2, for details.

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10.1 Metering Requirements and Guidelines

1) Meters designed for the expected flow conditions and range must be used to measure the following flare and vent streams:

   a) Continuous or intermittent flare and vent sources at all oil and gas production and processing facilities (excluding cold heavy oil and crude bitumen) where annual average total flared and vented volumes per facility exceed 0.5 10^3 m^3/day (excluding pilot, purge, or dilution gas). If all solution gas is flared or vented from any production facilities, the measured produced gas (less fuel gas use) may be used to report volumes flared or vented; in such situations, specific flare or vent gas meters are not required.

   b) Acid gas flared, either continuously or in emergencies, from gas sweetening systems regardless of volume.

   c) Fuel (dilution or purge) gas added to acid gas to meet minimum acid gas heating value requirements or *AAAQO*.

10.2 Estimating Requirements

The ERCB will accept estimates of flared, incinerated, and vented gas if measurement is not stated as a requirement in section 10.1 and the following conditions are met:

1) The licensee, operator, or approval holder must be able to demonstrate that reliable and consistent flared, incinerated, and vented gas estimating and reporting systems are in use (see CAPP's *Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities*, 2002).

   e) Estimating systems must account for all gas flared, incinerated, and vented from the facility (expressed to the nearest 0.1 10^3 m^3/month) during routine, emergency, and maintenance operations, well deliverability testing, and the depressurising of vessels, compressors, and pipelines.

   f) Volume estimates must be based on engineering calculations.

   g) Procedures or use of software for estimating flare and vent volumes must be developed by a technically knowledgeable person.

   h) If flared volumes are not measured by existing flare meters, a formal system for consistently estimating and reporting these volumes must be in place.

2) The licensee, operator, or approval holder must produce documentation describing flared and vented gas estimating and reporting procedures, as well as produce related operating logs, for review by the ERCB upon request.

3) For heavy oil / oil sands operations estimating requirements, see *Directive 017*.

4) The ERCB may require that meters be installed where there are failures to demonstrate adequate flare or vent gas estimating and reporting systems.

10.3 Flared, Incinerated, and Vented Gas Reporting

1) All flared and vented gas must be reported as described in ERCB *Directive 007*. Incinerated gas must be reported as "flared" gas if an incinerator is used in place of a flare stack. This would not apply to acid gas streams that are at a gas plant and that are

flared or incinerated as part of normal operations; in these cases, the flared or incinerated acid gas would be reported as acid gas shrinkage, not flared.

2) The licensee, operator, or approval holder must report, wherever possible, gas flared or vented at the facility where the flaring or venting took place. This helps industry and ERCB staff match up flaring or venting that is observed in the field with that reported. As part of PETRINEX, flared and vented gas at a facility must be reported separately.

3) When the flaring or venting location is on a gas gathering system but is not from a licensed entity,

   a) it must be reported as an activity associated with the closest licensed facility (e.g., compressor) on the gas gathering system; and

   b) if there is no licensed facility on the gas gathering system, it must be reported as an activity associated with the gas gathering system.

4) The licensee, operator, or approval holders must not prorate or allocate flared and vented volumes that occur at one facility to other upstream facilities.

5) If gas is flared or vented during drilling and completion, it must be reported to PETRINEX under the battery subtype code 381.

10.4 Flaring, Incineration, and Venting Records (Logs)

1) The licensee, operator, or approval holder must maintain a log of flaring, incineration, and venting events and respond to public complaints in order to comply with release reporting requirements.

   a) Release reporting requirements are defined in *IL 98-01* and ESRD's *Release Reporting Guideline*.

   b) Logs must include information on complaints related to flaring, incineration, and venting and how these complaints were investigated and addressed.

   c) Logs must describe each nonroutine flaring, incineration, and venting incident and any changes made to prevent future nonroutine events from occurring.

   d) Logs must include the date, time, duration, gas source or type (e.g., sour inlet gas, acid gas), and volumes for each incident.

   e) Logs must be kept for at least 12 months.

2) Flaring, incineration, and venting records must be made available to the ERCB upon request for each production facility, pipeline, and gas processing facility where flaring, incineration, and venting occur.

   a) A licensee, operator, or approval holder may retain logs for remote or semi-attended facilities at a central location (e.g., a regional office) where public complaints related to the facility in question would normally be received.

3) In situations governed by temporary flaring/incineration permits, a sour gas flaring/incineration data summary report (see appendix 6) must be completed in full and submitted to the ERCB Technical Operations Group within three weeks of the flaring/incineration completion date.

DRAFT for Consultation

Appendix 1 References and Contacts Cited

ERCB Documents*

Oil and Gas Conservation Regulations

Bulletin 2004-15: New Well Test Capture (WTC) System Implementation Date Reminder: Changes to Final WTC Pressure ASCII Standard (PAS) Formats and Version 4.0 PAS File Business Rules Implications

Directive 007: Volumetric and Infrastructure Requirements
Directive 008: Surface Casing Depth Requirements
Directive 017: Measurement Requirements for Oil and Gas Operations
Directive 019: Compliance Assurance
Directive 036: Drilling Blowout Prevention Requirements and Procedures
Directive 037: Service Rig Inspection Manual
Directive 038: Noise Control
Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators
Directive 040: Pressure and Deliverability Testing Oil and Gas Wells—Minimum Requirements and Recommended Practices
Directive 055: Storage Requirements for the Upstream Petroleum Industry
Directive 056: Energy Development Applications and Schedules
Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs
Directive 066: Requirements and Procedures for Pipelines
Directive 071: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry

General Bulletin (GB) 2002-05: EUB Requirements for Evaluation of Solution Gas Vent Gas Conservation

Interim Directive (ID) 91-03: Heavy Oil/Oil Sands Operations
ID 94-03: Underbalanced Drilling
ID 97-06: Sour Well Licensing and Drilling Requirements
ID 2001-03: Sulphur Recovery Guidelines for the Province of Alberta

Informational Letter (IL) 98-01: A Memorandum of Understanding Between Alberta Environment and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response

IL 2001-01: Appropriate Dispute Resolution (ADR) Program and Guidelines for Energy Industry Disputes

ERCBflare.xls and *ERCBincin.xls* spreadsheets
ERCBflare: A Screening Model for Non-routine Flaring Approvals and Routine Flare Air Dispersion Modelling for Sour Gas Facilities
ABflare: A Refined Air Quality Dispersion Model for Evaluating Non-routine Flaring for Sour Gas Facilities

ST13A: Alberta Gas Plant/Gas Gathering System Activities—Annual Statistics
ST13B: Alberta Gas Plant/Gas Gathering System Activities—Monthly Statistics
ST13C: Alberta Gas Gathering System Activities—Monthly Statistics
ST60: Crude Oil and Crude Bitumen Batteries Monthly Flaring, Venting, and Production Data
ST60A: Crude Oil and Crude Bitumen Batteries Annual Flaring, Venting, and Production Data
ST60B: Upstream Petroleum Industry Flaring and Venting Report

Alberta Energy Document

Information Letter (IL) 99-19: Otherwise Flared Solution Gas Royalty Waiver Program

Alberta Environment and Sustainable Resource Development

Air Quality Model Guideline
Alberta Ambient Air Quality Objectives and Guidelines
Environmental Protection and Enhancement Act
Non-routine Flaring Management: Modelling Guidance
Release Reporting Guideline 1028-F

Alberta Utilities Commission Document

Alberta Utilities Commission Rule 007: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations

Other Documents

Alberta Pressure Equipment Safety Regulations, Alberta Safety Codes Act, The Pressure Equipment Safety Authority (AR 49/2006)
ANSI/API-521, Pressure-Relieving and Depressuring System, American Petroleum Institute
Clean Air Strategic Alliance (CASA), 1998, Management of Routine Solution Gas Flaring in Alberta, Report and Recommendations of the Flaring Project Team (Edmonton, Alberta)
CAPP, 2013, Sour Non-routine Flaring Framework
CAPP, 2006, Best Management Practices for Facility Flare Reduction

(continued)

* ERCB documents are available on the ERCB Web site at www.ercb.ca and from Information Services, 250 – 5 Street SW, 10th Floor, Calgary AB T2P 0R4; Tel: 403-297-8190; Fax: 403-297-7040.

Other Documents (continued)

CASA, 2002, Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team (Edmonton, Alberta)

CASA, 2004, Gas Flaring and Venting in Alberta, Report and Recommendations for the Upstream Petroleum Industry, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

CASA, 2005, Flaring and Venting Recommendations for Coal Bed Methane Final Report, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

CASA, 2005, Flaring and Venting Review of Well Test Time Limits Final Report, Prepared by the Flaring and Venting Project Team for the Clean Air Strategic Alliance Board of Directors (Edmonton, Alberta)

Consumer Price Index forecast, Government of Alberta, Department of Finance website: www.finance.gov.ab.ca/aboutalberta/economic_bulletins/current_economic_indicators.pdf

Engineering and Geoscience Professsions Act, RSA 2000 c. E-11

Forest and Prairie Protection Act, RSA 2000 c. F19

Forest and Prairie Protection Regulations Part I and II (AR 135/72)

GLJ Petroleum Consultants Limited, *Commodity Price Forecast*, "Natural Gas and Sulphur Price Forecast Table"

Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team, CASA

GPSA Engineering Data Book (13th edition), Gas Processors Suppliers Association

Guide for Estimation of Flaring and Venting Volumes from Upstream Oil and Gas Facilities, CAPP

Industry Recommended Practice (IRP) Volume 4-2000/02: Well Testing and Fluid Handling, Canadian Petroleum Safety Council

PTAC Alberta Upstream Petroleum Research Fund Terms of Reference

ERCB Contacts

Facilities Applications Group: 403-297-4369
Well Test Helpline: 403-297-8952 (ext. 4)
Technical Operations Group: 403-297-6179
Field Centres
- Bonnyville: 780-826-5352
- Midnapore: 403-297-8303
- Drayton Valley: 780-542-5182
- Grande Prairie: 780-538-5138
- High Level: 780-926-5399
- Medicine Hat: 403-527-3385
- Red Deer: 403-340-5454
- St. Albert: 780-460-3800
- Wainwright: 780-842-7570

Fort McMurray Office: 780-743-7214

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Appendix 2 Definitions of Terms as used in *Directive 060*

Acid gas

Gas that is separated in the treating of solution or nonassociated gas that contains hydrogen sulphide (H_2S), total reduced sulphur compounds, and/or carbon dioxide (CO_2).

Associated gas

Gas that is produced from an oil or bitumen reservoir. This may apply to gas produced from a gas cap or in conjunction with oil or bitumen.

Carbon conversion efficiency (CCE)

The CCE quantifies the effectiveness of a device to oxidize hydrocarbons and is the relative conversion of carbon compounds in the reactants to products of complete and incomplete combustion. Incomplete combustion products include unburnt hydrocarbons (hydrocarbon [HC] measured as methane [CH_4]) and other partially oxidized carbon compounds, such as carbon monoxide (CO) in the exhaust. CCE is reported as the percentage of carbon in the fuel that is converted to CO_2 and is obtained from

$$CCE = \frac{Mass\ Rate\ of\ Carbon\ in\ the\ Fuel\ Converted\ to\ CO_2}{Mass\ Rate\ of\ Carbon\ in\ the\ Fuel}$$

With this definition, the mass and molar efficiency are the same. An adjustment must be made if there is CO_2 in the inlet stream, as it does not react. The adjustment depends on the fraction of $CO_{2,fuel}$ and hydrocarbons $C_X H_{Y,fuel}$ in the gas stream entering the device and the number of carbon moles (X) per molecule of hydrocarbon. CCE can be determined from exhaust and fuel concentration measurements using

$$CCE = \frac{CO_{2,stack} - (CO_{2,fuel} / (X C_X H_{Y,fuel}))(CO_{stack} + HC_{stack})}{(CO_{2,stack} + CO_{stack} + HC_{stack})}$$

This equation reduces to the following familiar expression if the inlet does not contain CO_2 ($CO_{2,inlet} = 0$):

$$CCE = \frac{CO_{2,stack}}{(CO_{2,stack} + CO_{stack} + HC_{stack})}$$

Clustering

The practice of gathering the solution gas from several flares or vents at a common point for conservation.

Combustion efficiency (CE)

The CE quantifies the effectiveness of a device to fully oxidize a fuel. Products of complete combustion (i.e., CO_2, H_2O, and sulphur dioxide [SO_2]) result in all of the chemical energy released as heat. Products of incomplete combustion (e.g., CO, unburnt hydrocarbons, other partially oxidized carbon compounds, H_2S, and other reduced and partially oxidized sulphur compounds) reduce the amount of energy released. CE is reported as the percentage of the net heating value that is released as heat through combustion.

Conservation

The recovery of solution gas for use as fuel for production facilities, other useful purposes (e.g., power generation), sale, or beneficial injection into an oil or gas pool.

Conservation efficiency

Conservation efficiency (%) =
(Solution gas production – Flared – Vented) / (Solution gas production) x 100

Conserving facility

Any potential tie-in point that is conserving gas, such as batteries, plants, compressor stations, pipelines, and pump stations.

Crude bitumen	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well.
Crude bitumen battery	An oil battery with crude bitumen production obtained from within the designated oil sands areas and that has a density of 920 kg/m^3 or greater at 15 degrees Celsius. To interpret well test duration limits, conservation timing, and conservation prebuild requirements, crude oil sites that are within the geographic area defined by the boundary of Township 45, Ranges 1 to 8, West of the 4th Meridian and Township 52, Ranges 1 to 8, West of the 4th Meridian and that are producing from the Mannville Group of formations are regulated as bitumen sites for the purpose of *Directive 060* only.
Crude oil	A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate or crude bitumen.
Crude oil battery	An oil battery with crude oil production in Alberta excluding heavy oil production inside the designated oil sand areas and inside the specified area producing from the Mannville Group of formations that are regulated as bitumen sites for the purpose of *Directive 060* only.
Emergency flaring	Emergency flaring occurs when safety controls within the facility are enacted to depressurize equipment to avoid possible injury or property loss resulting from explosion, fire or catastrophic equipment failure. Examples of upset flaring include: PSV overpressure; and emergency shut down
Fugitive emissions	Unintentional releases of gas resulting from production, processing, transmission, storage, and delivery.
Gas battery	A system or arrangement of tanks and other surface equipment (including interconnecting piping) that receives the effluent from one or more wells that might provide measurement and separation, compression, dehydration, dew point control, H_2S scavenging where <0.1 tonne/day of sulphur is being treated, line heating, or other gas handling functions prior to the delivery to market or other disposition. This does not include gas processing equipment that recovers more than 2 m^3/day of liquids or that processes more than 0.1 tonne/day of sulphur.
Gas processing plant	A system or arrangement of equipment used for the extraction of H_2S, helium, ethane, natural gas liquids, or other substances from raw gas; does not include a wellhead separator, treater, dehydrator, or production facility that recovers less than 2 m^3/day of hydrocarbon liquids without using a liquid extraction process (e.g., refrigerant, desiccant). In addition, does not include an arrangement of equipment that removes small amounts of sulphur (less than 0.1 tonne/day) through the use of nonregenerative scavenging chemicals that generate no H_2S or SO_2.
Heavy Oil	Crude oil having a density of 920 kg/m^3 or greater at 15°C.
Nonassociated gas	Gas produced from a gas pool (i.e., not associated with oil or bitumen reservoirs or with production).
Nonroutine flaring, venting, incineration	"Nonroutine" applies to intermittent and infrequent flaring venting and incineration. There are two types of nonroutine flaring: planned flaring and unplanned flaring.

Oil battery	A system or arrangement of tanks or other surface equipment or devices receiving the effluent of one or more wells for the purpose of separation and measurement prior to the delivery to market or other disposition.
Planned Flaring	Flare events where the operator has control over when flaring will occur, how long it will occur and the flow rates. Planned flaring results from the intentional de-pressurization of processing equipment or piping systems. Examples of planned flaring include pipeline blowdowns, equipment depressurization, start-ups, facility turnarounds, and well tests.
Qualified technical professional	A person holding an accredited professional qualification and acting within that person's professional scope of practice.
Risk-based criteria	Refer to the ESRD's *Non-Routine Flaring Management Modelling Guidance* for the purpose of *Directive 060* only.
Routine flaring, venting, incineration	"Routine" applies to continuous or intermittent flaring, venting, and incineration that occurs on a regular basis due to normal operation. Examples of routine flaring include: glycol dehydrator reboiler still vapour flaring; storage tank vapour flaring; flash tank vapour flaring; and solution gas flaring.
Screening assessment	This is the quickest and simplest dispersion modelling approach. Screening assessments usually provide a conservative (worst-case) estimate of downwind concentrations. If exceedances of the *Alberta Ambient Air Quality Objectives and Guidelines* are predicted by a screening assessment, a refined assessment may be necessary. Alternatively, stack design parameters may be modified until predicted ambient air quality meets the *Alberta Ambient Air Quality Objectives and Guidelines*.
Site	A single surface lease (pads counted as one lease) where gas is flared or vented
Solution gas	All gas that is separated from oil or bitumen production.
Sour gas	Natural gas, including solution gas, containing H_2S.
Source	All gas flared, incinerated, or vented from a single operating site, such as an oil battery or multiple-well pad.
Sulphur conversion efficiency (SCE)	The SCE quantifies the effectiveness of a device to oxidize sulphur and is the relative conversion of sulphur compounds in the reactants to products of complete and incomplete combustion. Incomplete combustion products include unburnt H_2S, other reduced sulphur compounds (measured as H_2S), such as carbonyl sulphide and carbon disulphide (especially if present in the fuel), and other partially oxidized sulphur compounds, such as sulphur trioxide (SO_3) in the exhaust (measured as SO_3). SCE is reported as the percentage of sulphur in the fuel that is converted to SO_2 and is obtained from $$SCE = \frac{Mass\ Rate\ of\ Sulphur\ in\ the\ Fuel\ Converted\ to\ SO_2}{Mass\ Rate\ of\ Sulphur\ in\ the\ Fuel}$$ With this definition, the mass and molar efficiency are the same. SCE can be determined from stack gas concentration measurements using $$SCE = \frac{SO_{2,stack}}{(SO_{2,stack} + SO_{3,stack} + H_2S_{stack})}$$
Sulphur emissions	All air emissions of sulphur-containing compounds, including SO_2, H_2S, and total reduced sulphur compounds (e.g., mercaptans). Sulphur emissions from flare stacks are expected to be primarily in the form of SO_2, with minor amounts of other compounds.

Sulphur recovery efficiency	Sulphur recovery efficiency = (sulphur produced + injected)/(sulphur produced + injected + sulphur emissions), where the sulphur emission is normally SO_2 expressed in sulphur equivalence. All values are units of mass.
Unplanned Flaring	Emergency or upset operational activities closely associated with facility health and safety. Flare events where the operator has no control of when flaring will occur. There are two types of unplanned flaring: upset flaring and emergency flaring.
Upset Flaring	Upset flaring occurs when one or more process parameters fall outside the allowable operating or design limits and flaring is required to aid in bringing the production back under control. Examples of upset flaring include: off-spec product; hydrates; loss of electrical power; process upset; and operation error.
Venting	The intentional controlled release of uncombusted gas.

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Appendix 3 Abbreviations

10^6 m^3	million cubic metres
10^3 m^3	thousand cubic metres
AAAQO	Alberta Ambient Air Quality Objectives and Guidelines
AOF	absolute open flow
APEGA	Association of Professional Engineers, and Geoscientists of Alberta
ASET	Association of Science and Engineering Technology Professionals of Alberta
AUPRF	Alberta Upstream Petroleum Research Fund
BMP	Best Management Practices
CAPP	Canadian Association of Petroleum Producers
CASA	Clean Air Strategic Alliance
CO_2	carbon dioxide
CSA	Canadian Standards Association
DDS	Digital Data Submission System
EPEA	Environmental Protection and Enhancement Act
ESDV	emergency shutdown valve
ESRD	Environment and Sustainable Resource Development
FIS	Field Information System
GOR	gas-to-oil ratio (gas:oil)
H_2S	hydrogen sulphide
HLSD	high-level shutdown
km	kilometre
kPa	kilopascal
mol/kmol	mole per kilomole
MJ	megajoule
MJ/m^3	megajoule per cubic metre
MW	megawatt
NOWPP	New Oil Well Production Period
NPV	net present value
NRFTT	Non-routine Flaring Task Team
ppm	parts per million
PRA	Petroleum Registry of Alberta (now PETRINEX)
PSV	pressure safety valve
PTAC	Petroleum Technology Alliance Canada
EPAC	Explorers and Producers Association of Canada
SO_2	sulphur dioxide

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Appendix 4 Background to *Directive 060*

Concerns about flaring prompted the EUB (now the ERCB) and Alberta Environment (now Alberta Environment and Sustainable Resource Development) to support Alberta Research Council research on flaring. Findings reported in 1996 suggested that the efficiency of flare stacks at destroying waste gas was not as high as originally thought and that various products of incomplete combustion were in flare emissions.

The EUB then consulted with stakeholders from industry, the public, and other government sectors and reviewed existing policies on solution gas conservation. CAPP brought the issue of flaring to the CASA board of directors in November 1996 and established the Flaring Project Team in February 1997 to develop recommendations to address potential and observed impacts of flaring. In its 1998 final report, *Management of Routine Solution Gas Flaring in Alberta: Report and Recommendations of the Flaring Project Team*, the Flaring Project Team recommended a framework for solution gas flaring management and a decision tree process for reducing flaring.

The EUB Implements the CASA Recommendations

In 1999 in the first edition of *Directive 060* (then called *Guide 60*), the EUB implemented the solution gas management framework (section 2), the decision tree process (section 2.3), and other CASA recommendations. The guide mandated firm, short-term solution gas flare reduction targets of 15 per cent and 25 per cent by the end of 2000 and 2001, respectively, relative to the 1996 revised baseline of 1340 10^6 m^3 per year; the guide also defined maximum limits on the total volume of solution gas that could be flared at individual sites if voluntary targets were not met.

In 2000, a new CASA team, the Flaring/Venting Project Team, convened to review progress made on the 1998 recommendations as well as make further recommendations on flaring, incineration, and venting. The result was the 2002 report, *Gas Flaring and Venting in Alberta: Report and Recommendations for the Upstream Petroleum Industry by the Flaring/Venting Project Team*. The report said that implementation of the solution gas management framework and the flare reduction targets by the upstream petroleum industry had successfully resulted in a 53 per cent reduction in solution gas flaring relative to the 1996 baseline.

On the basis of that success, the Flaring/Venting Project Team recommended that a similar decision tree process be applied to solution gas venting, well test flaring, and facility flaring. The team recommended that a 50 per cent reduction target be maintained for all solution gas flaring in Alberta relative to the 1996 baseline. Additional reports and recommendations were put forward in September 2004 and in March and June 2005. These recommendations were implemented through a rewrite of *Directive 060* released in November 2006. Significant changes included changing the economic threshold of the feasibility test for solution gas conservation from a net present value of zero to -$55,000. Also, economic evaluations were no longer required for sites that flared, incinerated, or vented less than 900 m^3/day of solution gas. Another significant addition to the directive was the concept of a duration limit for well test flaring and incineration.

Canadian Association of Petroleum Producers Recommendations

In 2004, CAPP established the Nonroutine Flaring Task Team (NRFTT) to review dispersion modelling requirements for intermittent and infrequent flaring. The NRFTT comprised government and industry. The CAPP document titled, *Sour Non-Routine Flaring Framework*

outlines the new regulatory approach and comprehensive plan for managing nonroutine flaring as developed by the NRFTT, and the process that led to its development.

Work on further reducing flaring, incineration, and venting continues.

Ongoing Research

The ERCB supports the 2004 CASA recommendations for additional research so that Alberta can continue to move toward the use of practical flare combustion efficiency standards where flaring is necessary. The ERCB expects that industry will support and participate in the funding of continued research focusing on

- understanding the relationship between gas composition and combustion efficiency, including the effects of H_2S content;
- understanding the effects of flare stack design, including flare tips on combustion efficiency; and
- reviewing the results of any field testing of combustion efficiency monitoring methodologies.

The ERCB supports the Petroleum Technology Alliance's (PTAC's) Alberta Upstream Petroleum Research Fund (AUPRF). AUPRF is an industry-sponsored fund supported by CAPP and EPAC. The objective of AUPRF is to provide an efficient and effective mechanism to coordinate, initiate, fund, complete and communicate on environmental research that is needed by the industry and government regulators to enable a prosperous upstream oil and gas industry that achieves socially and environmentally responsible recovery of Canada's petroleum resources through effective, market-driven collaboration. AUPRF supports practical science-based studies that develop credible and relevant information to address knowledge gaps in the understanding and management of high priority environmental and social matters related to oil and gas exploration and development in Alberta. Research reports are shared broadly with the oil and gas industry as well as with regulators, government agencies, and other stakeholders.

DRAFT for consultation

Appendix 5 Information for Permit Request to Flare or Incinerate in Exceedance of Flared or Incinerated Volume Allowance Threshold (600, 400, or 200 10^3 m^3 Exceedance)

If flared or incinerated volumes are expected to exceed the volume allowance threshold during temporary operations, more information must be submitted to the ERCB.

1) Underbalanced drilling requests must include the following information:
   a) an explanation and supporting documentation on how flaring or incineration rates are determined; possible sources of these estimates are
      i) offset well AOF tests, or
      ii) flaring or incineration rates from offset underbalanced drilling operations;
   b) the estimated time required to drill the well;
   c) if a well test is proposed, the total volume requested for the test.

2) For well tests that are expected to exceed the volume allowance threshold, the request must include the following information:
   a) A brief description of the development required to bring the well onto production (e.g., length and size of pipeline to tie in well, well site facilities, compression, gas processing facilities)
   b) The minimum recoverable reserves required for the well to be economic (minimum economic reserves)
   c) Details of the analysis used to determine the minimum economic reserves. Licensees may use simplified "netback" economics showing the current operating profit (revenues minus operating costs) to estimate the recoverable reserves required to pay out facility investment costs; alternatively, licensees may choose to present a more detailed economic analysis involving features such as discounted gas flow projections)
   d) The estimated recovery factor and surface loss for the pool
   e) The estimated initial reservoir pressure
   f) The amount of reservoir depletion being targeted by the test (the licensee must provide a brief description justifying this depletion in relation to the minimum economic reserve). The recommended maximum pressure depletion guidelines are
      i) 1 per cent of the first 5000 kPa of reservoir pressure, and
      ii) 0.5 per cent of the reservoir pressure above 500 kPa.

      For example, a maximum depletion guideline of 100 kPa is targeted for a reservoir with an initial pressure of 15 000 kPa.
   g) Justification for pretest cleanup and servicing flaring or incineration if related volumes exceed 200 10^3 m^3

Note that an incremental volume of up to 200 10^3 m^3 may be added to the permit request in order to provide for pretest cleanup and servicing operations if these are needed to establish the minimum economic reserve without additional justification.

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Appendix 6 Sour Gas Flaring/Incineration Data Summary Report

This form must be completed in full and submitted to the ERCB's Field Surveillance and Operations Branch within three weeks of the flaring completion date or, in the event no flaring took place, within three weeks of the expiry date:

Submit to: **Flaring Approvals** **Fax: (403) 297-2691** **E-mail: Directive060Inbox@ercb.ca**
11th Floor – Field Surveillance and Operations Branch
Energy Resources Conservation Board
Suite 1000, 250 5th St. SW
Calgary, AB T2P 0R4

Item	Report Information		
Approval No:			
Company:			
Well Name:			
Unique Well Identifier:			
Approval Issue Date:	Expiry Date:		
Volume of Formation Gas Flared:	Approved: _____ 10^3m^3	Actual: _____ 10^3m^3	
Instantaneous Flared Gas Flow Rate:	Approved (Max.): _____ $10^3m^3/d$	Actual (Max.): _____ $10^3m^3/d$	Actual (Avg.): _____ $10^3m^3/d$
Actual Fuel Gas Flared (if applicable):	Volume: _____ 10^3m^3	Rate: _____ $10^3m^3/d$	
Number of H_2S Analyses Conducted:	(Please provide tester report)		
H_2S Content of Raw Gas:	Approved (Max.): _____ %	Actual (Max.): _____ %	Actual (Avg.): _____ %
Total Sulphur Flared:	_____ tonnes	[= 1.35592 (%H_2S÷100) (flared vol.)]	
Flaring Dates:			
Management Plan Required?	☐ No ☐ Yes		
Meteorological Monitoring Conducted?	☐ No ☐ Yes (If yes, please provide electronic copy of monitoring report)		
Air Monitoring Conducted?	☐ No ☐ Yes (If yes, please provide electronic copy of monitoring report)		
Exceedances of the Alberta Ambient Air Quality Guidelines (H_2S or SO_2):	☐ No ☐ Yes (If yes, please provide comments)		
Field Centre Notification Date:		ERCB Field Centre Contact:	
Were there any problems while flaring? If Yes, was the ERCB Field Centre Contacted?	☐ No ☐ Yes ☐ No ☐ Yes	If yes, contact name:	
Comments:			
Company Representative:			
Phone Number:	E-mail:		
Fax Number:	Signature:		

Appendix 7 Air Quality Management Plans for Temporary SO_2 Emissions

If exceedances of the risk-based criteria for SO_2 (see appendix 8) are predicted and it is not proposed that flare/incinerator design parameters be altered to mitigate the potential exceedances, approval may be granted by the ERCB if suitable control measures are in place. In such situations, an air quality management plan must be submitted with the temporary permit request. **The management plan must outline how predicted exceedances of the *Alberta Ambient Air Quality Objectives and Guidelines* will be avoided so that the risk-based criteria are met.**

The air quality management plan may include the following:

1) Restrictions during specific meteorological conditions that will limit or avoid operations under conditions that result in predicted exceedances.
   a) These atmospheric conditions may include
      i) time of day,
      ii) wind direction,
      iii) wind velocity, and
      iv) atmospheric stability.
   b) Meteorological monitoring may be used as a management plan based on a maximum one-hour rolling (i.e., any consecutive 60 minutes), with measurements taken at a frequency of no more than every 15 minutes (i.e., four measurements/hour).

2) The management plan must include specifications for locating meteorological monitoring equipment (if used). Wind monitoring devices must be elevated above the height of trees surrounding the site.

3) Restrictions that may be applied during unfavourable meteorological conditions.
   a) Operational restrictions in air quality management plans may include
      i) suspension of flaring or incineration operations,
      ii) reduction or increase of flaring or incineration rates, and
      iii) requirements that supplemental fuel gas meet a minimum heating value or exit velocity.

4) If a reduction in flaring or incineration rate or an addition of supplemental fuel gas is proposed, compliance with the risk-based criteria must be demonstrated with appropriate dispersion modelling results. (Note that reduced flaring or incineration rates do not result in a proportional reduction in predicted concentrations.)

5) Ambient air monitoring (mobile and/or stationary) must be located where exceedances of the *Alberta Ambient Air Quality Objectives and Guidelines* are predicted.
   a) Ambient air monitoring in conjunction with appropriate flaring/incineration management procedures will only be accepted when it can be demonstrated that monitors can be placed in a manner that is reasonably protective of all locations where exceedances of the risk-based criteria are predicted. Stationary monitors are currently accepted to cover an arc of 22.5°C centred on the source. The licensee or operator must provide an National Topographic System (NTS) map of the area (1:50 000) indicating the locations of the stationary monitors and a table with the

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coordinates (i.e., [Universal Transverse Mercator (UTM)]). In cases where monitoring is proposed, a licensee or operator must demonstrate that there is good access to all areas with predicted exceedances *before* a request is submitted.

b) The *Alberta Ambient Air Quality Objectives and Guidelines* must not be exceeded, based on a one-hour average. To accomplish this, ambient air monitoring must occur at intervals of 15 minutes or less. **If the 30-minute average exceeds the *Alberta Ambient Air Quality Objectives and Guidelines*, the flaring or incineration operation must be immediately shut in.**

6) If there is more than one meteorological condition that requires a management response, or if a combination of meteorological restrictions and ambient air monitoring is proposed, the management plan must be summarized in a flowchart that is clear and concise and can be applied by on-site staff during flaring or incinerating operations. Furthermore, if multiple flow rates are proposed in the management plan, the risk-based criteria must be met for each flow rate.

a) The management plan must clearly specify the frequency at which the meteorological or ambient air quality monitoring data will be monitored by on-site staff. An averaging time of no more than 15 minutes is mandatory, as this allows for observations of trends and provides enough time to respond to elevated concentrations.

7) The management plan must clearly define under what conditions flaring or incineration may resume if suspended or may return to normal operations if a management option such as fuel gas is proposed. Flaring or incineration must remain suspended for at least one hour before operations may resume in order to prevent an exceedance or to respond to an exceedance.

a) Flaring or incineration may begin again after one hour or after meteorological conditions change and remain favourable for 30 minutes, whichever is longer.

8) Real-time dispersion modelling flare management plans must be based on maximum predicted concentrations. Pseudo input parameters must be calculated using *ERCBFlare*. If real-time dispersion modelling goes down, the operator must revert to a conventional flare management plan or shut in.

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Appendix 8 Screening Dispersion Modelling Using ERCB Spreadsheet

The ERCB sour well test flaring and incineration permit spreadsheets and technical descriptions are available on the ERCB website www.ercb.ca under ERCB Directives : Directive 060. They provide a screening analysis of the SO_2 and H_2S dispersion from permanent and temporary flares and incinerators. If the screening level maximum concentration predictions in parallel and complex airflow terrain for a source meet the *Alberta Ambient Air Quality Objectives and Guidelines* (*AAAQO*), no further analysis is required. The spreadsheet can be submitted in support of the dispersion modelling assessment.

Maximum predictions for routine sources must meet the *AAAQO*. Due to the short-term nature of temporary nonroutine sources, risk-based criteria can be applied. The risk-based criteria apply to well tests and other temporary nonroutine flaring and incineration events. For further information about the spreadsheet refer to the *ERCB flare User Guide: A Screening Model for Non-routine Flaring Approvals and Routine Flare Air Dispersion Modelling for Sour Gas Facilities*.

If it is not practical to modify flare or incinerator design parameters, you may consider evaluating the proposed design with more refined dispersion modelling approaches. Additional refined dispersion modelling is required if the screening level maximum concentration predictions in parallel and complex airflow terrain for a source do not meet the *AAAQO*. A refined dispersion modelling assessment is also required if there are continuous SO_2 emission sources within 10 km of the location or within the isopleth of one-third of the *AAAQO* for SO_2 (as described in section 7.12.3), whichever distance is less. This requires that the cumulative effects of the proposed flaring or incineration be assessed in combination with other sources. A refined dispersion modelling assessment must meet ESRD's *Air Quality Model Guideline* (2013) or *Non-Routine Flaring Management: Modelling Guidance* (2013).

A licensee, operator, or approval holder is responsible for ensuring that appropriately trained and qualified personnel complete the air quality evaluations.

A refined dispersion modelling assessment must include the following:

1) A description of the meteorological data source (location, years, and months). For models that require meteorological data, five years of meteorological data from a standard period is recommended. Three months per year must be modelled from the data set centred about the month of the requested permit date. The acceptable data sets are posted on the ESRD website at http://www.environment.alberta.ca/01119.html. Additional information about modelling and meteorological data requirements is on the ESRD website.
2) A wind rose (a representation of the history of wind directions and wind speeds).
3) Refined modelling source parameters for maximum flow rate (Q_{max}), average flow rate (Q_{avg}), and one-eighth maximum flow rate (Q/8) from the spreadsheet.
4) A summary of the model input parameters (a printed copy of the input file is preferred, as output files may be large and need not be submitted).
5) The maximum predicted one-hour ambient air SO_2 concentration for maximum flow rate (Q_{max}), average flow rate (Q_{avg}), and one-eighth maximum flow rate (Q/8).
6) If exceedances of the one-hour *AAAQO* for SO_2 are predicted, a histogram of the overall probability of exceedance based on meteorological data is to be calculated, as follows, by

dividing the number of hours with predicted exceedances by the total number of hours used in the meteorological data set:

$$\text{Probability of exceedance} = \frac{\text{(Cumulative number of hours with predicted exceedances)}}{\text{(Total hours modelled)}}$$

7) An interpretation of the modelling results (output files or model result printouts may be included if not excessively large).

8) Histograms showing exceedances based on criteria (e.g., wind direction, wind speed, and stability class).

If the risk-based criteria are not met, a management plan (see Appendix 7) must be developed to achieve the risk-based criteria. Requests with management plans must include enough information so that the ERCB can assess the management plan, including

1) for each flow rate, a summary table of output, including
   - meteorological conditions (stability class and range of wind speeds and directions) or times of day that result in predicted exceedance of the one-hour *AAAQO* for SO_2,
   - maximum predicted SO_2 concentration for each condition where exceedances are predicted, and
   - the expected overall probability of exceedances before and after implementation of the management plan;
2) for each flow rate, an area map showing
   - locations of predicted SO_2 ground-level concentration isopleths (with a minimum 10 km radius) in excess of the one-hour *AAAQO* for SO_2,
   - sectors with flaring restrictions (if proposed),
   - locations accessible with a mobile monitoring unit (if proposed),
   - approximate location of proposed stationary monitors (if proposed) and, if available, a recent air photo showing the approximate location of proposed stationary monitors, as well as specifications of the monitor location in a format usable by the monitoring licensee, operator, or approval holder (e.g., UTM coordinates or latitude and longitude), with an acceptable offset distance if this is required to improve access or telemetry line of site; site reconnaissance must be conducted before submission to ensure that monitors can be placed, and
   - UTM coordinates of stationary monitors, as well as distance and direction from well;
3) a calculation of make-up fuel gas requirements as a percentage of the produced gas being combusted (fuel gas may be used to increase plume rise; care should be taken to minimize fuel gas waste); and
4) electronic copies (i.e., Microsoft Word or Excel files) of the management plan and decision tree (if applicable).

The *ERCBflare.xls* and *ERCBincin.xls* spreadsheets also evaluate minimum and maximum exit velocities with respect to down-wash criteria. The results will help the licensee, operator, or approval holder optimize flare and incinerator design and verify parameters used for temporary flaring and incineration permit requests.

1) If down-wash is predicted, the spreadsheet source parameters will conservatively account for down-wash; however, it is recommended that the stack design parameters (e.g., stack diameter) be modified to avoid down-wash.

2) The spreadsheet provides maximum and minimum exit diameters based on the recommended exit velocities. You must size the exit diameter within the range of exit diameters provided in *ERCBflare.xls*. Exit diameter is a permitted parameter. A qualified technical professional who is a member of the association as defined in the *Engineering and Geoscience Professions Act*[26] must review the design parameters.

The licensee, operator, or approval holder may submit data based on modified modelling methods for consideration; however, results from one of the accepted unmodified models must also be submitted for comparison. Description and scientific justification of the modifications must be provided. Generally, review of permit requests that use a modified modelling method requires more time, and the ERCB may accept or reject the modified results at its discretion.

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[26] Engineering and Geoscience Professions Act RSA 2000 c. E-11, as amended

Appendix 9 Resident Flaring/Venting/Incinerating Notification Sample Form

We will be flaring/incinerating/venting a (___ % H_2S) well in accordance with ERCB *Directive 060* at the location stated below.

Flaring/Incinerating/Venting Category (check those that apply)	ERCB Office (check one)	
Well test flaring	Bonnyville	(780-826-5352)
Well test venting	Drayton Valley	(780-542-5182)
Well test incinerating	Grande Prairie	(780-538-5138)
	Fort McMurray	(780-743-7214)
(Check one)	High Level	(780-926-5399)
Oil well	Medicine Hat	(403-527-3385)
Gas well	Midnapore	(403-297-8303)
	Red Deer	(403-340-5454)
	St. Albert	(780-460-3800)
	Wainwright	(780-842-7570)

Flaring/Venting/Incinerating Comments	
Well Licence No.	
Well Name	
Location of Well (LSD)	
Estimated Flare/Incinerate/Vent Timing (30-day window)*	
Estimated Start Date	
Estimated End Date	
Flaring/Incinerating/Venting Duration	
Estimated Volume (10^3 m^3/day)	
Licensee or Operator Name	
Licensee or Operator Representative	
Contact Phone Number	
Testing Contractor	
Testing Representatives on Site	
Daytime Cell Phone Number	
Nighttime Cell Phone Number	
Emergency Phone Number	

Please phone (___) ___ - ____ if you would like notification 24 or 48 hours in advance of flaring/ incinerating/venting operations.

- 30-day window is to accommodate for weather and operational delays.
- Renotification is mandatory after 90 days.

Note:_____

_____

If you have questions or concerns, please phone (___) ___ - _____

Appendix 10 Agreement on Zero Flaring

The following serves to outline the agreement between _____ (applicant) and _____ (landowner or occupant) respecting flaring at the well located at _____W___. The applicant agrees to not flare from the well before putting the well on production except as stated below in this agreement or in an emergency. **Venting is not to be used as an alternative to flaring.**

Exceptions

Flaring may occur as indicated below and is limited to at most two of the activities:

- Well testing Yes? ____ No?_____
- Well cleanup Yes? ____ No?_____
- Drillstem testing Yes? ____ No?_____

Emergencies

The licensee, operator, or approval holder may flare in emergency situations for safety of the public or environmental protection.

If the ownership of the well is transferred to another licensee, operator, and/or approval holder, this agreement will remain in effect for the new licensee, operator, or approval holder and it is the licensee, operator, or approval holder's responsibility to advise any successors of this agreement.

This agreement no longer applies once this well is tied into a production facility or once production operations begin.

Applicant Signature_____ Landowner or Occupant Signature (optional)_____

Printed Name _____ Printed Name_____

Licensee, operator, or approval holder _____

Location_____

Telephone_____ Telephone_____

E-mail/Fax_____ E-mail/Fax_____

Date _____

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Appendix 11 Request to Extinguish Sour Gas Flare Pilots

The following minimum requirements must be met in any situation where it is proposed to extinguish a flare pilot at a sour facility:

1) The maximum stabilized wellhead pressure must be determined based on the measured stabilized static wellhead pressure corrected for the hydrostatic head of any liquid present in the wellbore at the time of testing.

   a) This correction for the liquid column hydrostatic head must use the density of the produced water for the entire fluid column present in the wellbore.

   b) The maximum stabilized static wellhead pressure must be determined by a qualified well test professional using accepted engineering practices. ERCB *Directive 040* provides regulations for conducting pressure tests on wells.

2) The following features must be incorporated into the facility for consideration of the request to extinguish the flare pilot:

   a) Nonfragmenting rupture disks must be installed on the upstream side of all pressure safety valves (PSVs). This is subject to section 38(1)(b) of the *Pressure Equipment Safety Regulation* (AR 49/2006) administered by the Alberta Boilers Safety Association.

      - A pressure gauge or suitable telltale indicator must be installed between each rupture disk and the corresponding PSV to allow detection of leakage or a disk rupture.

   b) Two block valves in series must be installed for manual depressurizing valves connected to the flare.

   c) The battery must be equipped with a pressure sensor, automatic emergency shutdown valves (ESDVs), and a control system configured to isolate the battery from the well and outlet gas pipeline. There must be no automatically controlled emergency depressurizing valves connected to the flare.

3) Upstream piping to the well must be designed for the maximum pressure that might be encountered. The *minimum* operating requirements for any facility approved for extinguishing flare pilots include the following:

   a) The licensee, operator, or approval holder must monitor and document on a weekly basis the pressure between rupture disks and PSVs.

   b) If a rupture disk fails or if odours result from gas released to the flare stack, the flare stack must be lit and immediate notification must be given to the appropriate ERCB field centre, followed by a written incident report giving particulars. Approval to extinguish the flare pilot is then considered void until the licensee, operator, or approval holder demonstrates to the satisfaction of the appropriate ERCB field centre that related problems have been successfully corrected.

   c) The sweet gas or propane pilot must be ignited prior to any flaring or depressurizing at the site.

   d) The operation of the emergency shutdown system, including ESDVs, must be verified and documented at least once a year.

   e) ERCB approval to extinguish the flare pilot must be visibly displayed at each site.

4) Residents within the emergency planning zone (EPZ) must be notified of plans to extinguish the flare pilot.

   a) Any concerns or objections of residents to extinguishing pilots must be addressed. Refer to the dispute resolution process discussed in section **Error! Reference source not found.** for guidance.

5) The following information must accompany the licensee's, operator's, or approval holder's request to extinguish flare pilots:

   a) a list of all wells connected to the battery, including

      i) normal wellhead operating pressure, and

      ii) maximum stabilized static wellhead pressure;

   b) the maximum design operating pressure of the piping and pressure vessel systems for the battery, including

      i) a list of all PSVs connected to the flare and related release set-pressures, and

      ii) a list of related rupture disks and burst pressures;

   c) written confirmation that

      i) none of the wells connected to the facility are completed in pools that have active injection or cycling schemes,

      ii) rupture disks on PSVs and two valves in series have been installed on all streams tied into the flare system,

      iii) maximum H_2S release rates will not exceed the level-1 or -2 sour well classification,

      iv) residents within the EPZ have been notified, and

      v) high-pressure shutdowns are in place, with a statement confirming calibration frequency.

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Appendix 12 Directive 60 Area Regulated as Bitumen Sites